UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of earliest event reported: November 19, 2001

THE MONTANA POWER COMPANY

(Exact name of registrant as specified in its charter)

Montana	**1-4566**	**81-0170530**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

40 East Broadway, Butte, Montana	**59701-9394**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(406) 497-3000**

ITEM 5. Other Events

We are filing this Current Report on Form 8-K to update and amend the Report of Independent Accountants, Consolidated Financial Statements, and related Management's Discussion and Analysis of Financial Condition and Results of Operations (2000 MD&A) contained in our 2000 Annual Report on Form 10-K for the period ended December 31, 2000 (2000 Form 10-K). This update is filed solely to include: (i) a revised opinion of the Company's Independent Accountants; (ii) the addition of Note 17 to the Notes to the Consolidated Financial Statements; and (iii) additional disclosure in two paragraphs under the heading "Financing Activities" in the 2000 MD&A relating to, among other matters, a waiver of the requirement to comply with two financial covenants under Touch America's Credit Facility (as defined herein); which reflect information in The Montana Power Company (Company) Form 10-Q for the period ended September 30, 2001 (Third Quarter 10-Q). The Third Quarter 10-Q also contains a discussion of the Company's borrowings under its credit facilities, which expire by the end of November 2001, and the Company's plan to refinance its borrowings under the credit facilities.

To preserve the nature and character of the disclosures originally set forth in our 2000 Form 10-K, this Form 8-K does not otherwise update the 2000 Form 10-K or reflect events occurring after the filing date of our 2000 Form 10-K.

ITEM 7. Financial Statements and Exhibits.

Exhibit

23	Consent of Independent Accountants.
99a	Amended Report of Independent Accountants and Consolidated Financial Statements for the twelve months ended December 31, 2000.
99b	Amended Management’s Discussion and Analysis of Financial Condition and Results of Operations for the twelve months ended December 31, 2000.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

THE MONTANA POWER COMPANY
(Registrant)

By /s/ J.P. Pederson
J.P. Pederson
Vice Chairman and Chief Financial Officer

Dated: November 19, 2001

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Exhibit 23

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Prospectuses constituting part of the Registration Statements on Form S-3 (No. 33-43655, 333-28877, 33-32275, 33-55816, 333-14369, 333-14369-01, and 333-17181), and to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-59573, 33-24952 and 33-28096), of our report dated February 21, 2001, except for Note 17, which is as of November 14, 2001, appearing on page 9 of The Montana Power Company's Current Report on Form 8-K dated November 19, 2001.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
November 19, 2001

Exhibit 99a

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Financial Statement Schedules not included in this Form 8-K have been omitted because they are inapplicable or the required information is shown in the Consolidated Financial Statements or in the Notes to the Consolidated Financial Statements.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of The Montana Power Company is responsible for the preparation and integrity of the consolidated financial statements of the Company. These financial statements have been prepared in accordance with generally accepted accounting principles, which are consistently applied, and appropriate in the circumstances. In preparing the financial statements, management makes appropriate estimates and judgments based upon available information. Management also prepared the other financial information in the Current Report on Form 8-K and is responsible for its accuracy and consistency with the financial statements.

Management maintains systems of internal accounting control, which are adequate to provide reasonable assurance that the financial statements are accurate, in all material respects. The concept of reasonable assurance recognizes that there are inherent limitations in all systems of internal control in that the costs of such systems should not exceed the benefits to be derived. Management believes the Company's systems provide this appropriate balance.

The Company maintains an internal audit function that independently assesses the effectiveness of the systems and recommends possible improvements. PricewaterhouseCoopers LLP, the Company's independent accountants, also considered the systems in connection with its audit. Management has considered recommendations of the internal auditors and PricewaterhouseCoopers LLP concerning the systems and has taken cost-effective actions to respond appropriately to these recommendations.

The Board of Directors, acting through an Audit Committee composed entirely of directors who are not employees of the Company, is responsible for determining that management fulfills its responsibilities in the preparation of the financial statements. The Audit Committee recommends, and the Board of Directors appoints, the independent accountants. The independent accountants and internal auditors are assured of full and free access to the Audit Committee and meet with it to discuss their audit work, the Company's internal controls, financial reporting, and other matters. The Committee is also responsible for determining adherence to the Company's Code of Business Conduct (Code). The Code addresses, among other things, potential conflicts of interests and compliance with laws, including those relating to financial disclosure and the confidentiality of proprietary information.

The financial statements have been audited by PricewaterhouseCoopers LLP, which is responsible for conducting its examination in accordance with generally accepted auditing standards.

/s/ Robert P. Gannon
Chairman of the Board and
Chief Executive Officer

/s/ J.P. Pederson
Vice Chairman and
Chief Financial Officer

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of The Montana Power Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of The Montana Power Company and its subsidiaries at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As more fully discussed in Note 1 to the Consolidated Financial Statements, as of July 1, 1999, the Company changed its method of accounting for revenues relating to certain agreements to grant and exchange fiber-use rights.

As discussed in Note 17 to the consolidated financial statements, Touch America, Inc. (Touch America), a wholly owned consolidated subsidiary of the Company, was not in compliance with certain financial covenants under its credit facility based on financial performance for the twelve months ended September 30, 2001. Touch America on November 14, 2001 received a thirty-day waiver relating to such covenants but has not yet restructured its credit facility nor secured additional funds to meet its future cash requirements. If Touch America does not reach agreement with the lending banks under its credit facility or receive additional funds from other sources, the recorded value of Touch America's assets included in the Company's consolidated balance sheet may not be realized or recovered in the ordinary course of business. Management's plans in regard to these matters are also described in Note 17.

/s/ PricewaterhouseCoopers LLP
Portland, Oregon

February 21, 2001, except for Note 17, which is as of November 14, 2001

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF INCOME

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars) (except per-share amounts)		
REVENUES	$999,708	$777,172	$770,957
EXPENSES:			
Operations and maintenance	612,712	370,870	366,400
Selling, general, and administrative	171,373	116,864	98,239
Taxes other than income taxes	60,991	71,933	67,088
Depreciation, depletion, and amortization	77,026	79,576	85,245
	922,102	639,243	616,972
INCOME FROM CONTINUING OPERATIONS	77,606	137,929	153,985
INTEREST EXPENSE AND OTHER INCOME:			
Interest expense	34,408	41,593	59,373
Distributions on company obligated mandatorily redeemable preferred securities of subsidiary trust	5,492	5,492	5,492
Other income - net	(72,085)	(38,407)	(103,419)
	(32,185)	8,678	(38,554)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	109,791	129,251	192,539
INCOME TAXES	33,598	30,830	66,843
INCOME FROM CONTINUING OPERATIONS	76,193	98,421	125,696
DISCONTINUED OPERATIONS:			
Income from discontinued coal operations (less applicable income taxes of $8,234, $5,656, and $10,553)	31,897	37,400	30,181
Income from discontinued oil and natural gas operations (less applicable income taxes of $17,940, $7,577, and $778)	29,395	14,525	9,743
Gain on sale of discontinued oil and natural gas operations (less applicable income taxes of $42,769)	62,006	-	-
INCOME FROM DISCONTINUED OPERATIONS	123,298	51,925	39,924
NET INCOME	199,491	150,346	165,620
DIVIDENDS ON PREFERRED STOCK	3,690	3,690	3,690
NET INCOME AVAILABLE FOR COMMON STOCK	$ 195,801	$ 146,656	$161,930
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - BASIC (000)	105,451	109,795	109,962
BASIC EARNINGS PER SHARE OF COMMON STOCK	$ 1.86	$ 1.34	$ 1.47
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - DILUTED (000)	106,353	110,553	110,156
DILUTED EARNINGS PER SHARE OF COMMON STOCK	$ 1.84	$ 1.33	$ 1.47

The accompanying notes are an integral part of these financial statements.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

ASSETS

	December 31 2000	December 31 1999
	(Thousands of Dollars)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 118,417	$ 554,407
Temporary investments	-	40,417
Accounts receivable, net of allowance for doubtful accounts	300,298	182,248
Materials and supplies (principally at average cost)	16,446	37,928
Prepayments and other assets	71,806	53,733
Deferred income taxes	17,738	18,303
Investment in discontinued coal operations	93,870	-
	618,575	887,036
PROPERTY, PLANT, AND EQUIPMENT:		
Utility plant, less accumulated depreciation, depletion, and amortization	1,083,611	1,048,892
Nonutility plant, less accumulated depreciation, depletion, and amortization	613,175	655,843
	1,696,786	1,704,735
OTHER ASSETS:		
Intangibles, net of amortization	152,409	922
Reclamation fund	-	43,460
Telecommunications investments	30,448	39,678
Other investments	66,495	76,382
Advanced coal royalties	-	12,506
Regulatory assets related to income taxes	60,423	60,538
Regulatory assets - other	142,434	150,486
Deferred income taxes	21,419	-
Other	27,805	73,000
	501,433	456,972
TOTAL ASSETS	$ 2,816,794	$ 3,048,743

The accompanying notes are an integral part of these financial statements.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

LIABILITIES AND SHAREHOLDERS' EQUITY

	December 31 2000	December 31 1999
	(Thousands of Dollars)	
CURRENT LIABILITIES:		
Accounts payable	$ 206,924	$ 115,654
Dividends payable	1,456	22,746
Income taxes payable	104,093	152,739
Other taxes payable	41,054	54,630
Regulatory liability - oil and natural gas sale	32,549	-
Current portion of deferred revenue	45,771	24,962
Short-term borrowing	75,000	-
Long-term debt due within one year	169,054	58,955
Interest accrued	5,679	11,597
Other current liabilities	38,422	67,315
	720,002	508,598
LONG-TERM LIABILITIES:		
Deferred income taxes	-	8,847
Investment tax credits	13,163	13,330
Deferred reclamation	-	135,075
Deferred revenue	235,578	311,751
Regulatory liability - net proceeds from the generation sale in excess of book value	214,887	219,726
Other deferred credits	94,689	101,434
	558,317	790,163
LONG-TERM DEBT:		
Long-term debt	309,463	618,512
Company obligated mandatorily redeemable preferred securities of subsidiary trust which holds solely company junior subordinated debentures	65,000	65,000
	374,463	683,512
SHAREHOLDERS' EQUITY:		
Preferred stock	57,654	57,654
Common stock (240,000,000 shares without par value authorized; 110,358,934 and 110,218,973 shares issued)	705,157	702,773
Treasury stock (6,616,000 and 4,682,100 shares authorized, issued, and repurchased by the Company)	(205,656)	(144,872)
Unallocated stock held by trustee for retirement savings plan	(17,227)	(20,401)
Retained earnings	624,118	488,975
Accumulated other comprehensive loss	(34)	(17,659)
	1,164,012	1,066,470
CONTINGENCIES AND COMMITMENTS (Notes 13 and 14)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,816,794	$ 3,048,743

The accompanying notes are an integral part of these financial statements.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
NET CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 199,491	$150,346	$165,620
Deduct:			
Income from discontinued operations	61,292	51,925	39,924
Gain on sale of discontinued oil and natural gas operations	62,006	-	-
Income from continuing operations	76,193	98,421	125,696
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:			
Depreciation, depletion, and amortization	77,026	79,576	85,245
Write-downs of long-lived assets	-	7,083	-
Deferred income taxes	(44,513)	(315,588)	(42,258)
Noncash earnings from unconsolidated investments	(15,227)	(20,608)	(10,871)
(Gains) losses on sales of property and investments	(28,631)	67	5,651
Other noncash charges to net income - net	5,020	25,154	32,131
Changes in assets and liabilities:			
Accounts and notes receivable	(142,177)	12,333	(30,393)
Deferred income taxes	(11,039)	3,379	(4,745)
Income taxes payable	(164,715)	129,228	21,582
Accounts payable	106,586	26,244	(8,031)
Deferred revenue and other	(72,511)	291,790	11,800
Miscellaneous temporary investments	40,417	(40,417)	-
Regulatory liability - net proceeds from the generation sale in excess of book value	-	219,726	-
Other assets and liabilities - net	64,626	104,414	34,678
Net cash provided by (used for) continuing operations	(108,945)	620,802	220,485
Net cash provided by discontinued operations	53,068	39,381	35,192
Net cash provided by (used for) operating activities	(55,877)	660,183	255,677
NET CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(644,216)	(233,192)	(151,044)
Proceeds from sale of discontinued oil and natural gas operations	474,993	-	-
Proceeds from sales of property and investments	83,912	586,150	38,063
Additional investments	(2,050)	(1,272)	(7,732)
Net cash provided by (used for) continuing investing activities	(87,361)	351,686	(120,713)
Net cash used for discontinued investing activities	(46,516)	(45,182)	(38,839)
Net cash provided by (used for) investing activities	(133,877)	306,504	(159,552)
NET CASH FLOWS FROM FINANCING ACTIVITIES:			
Dividends paid	(67,053)	(90,902)	(91,598)
Sales of common stock	2,525	751	7,421
Purchase of treasury stock	(60,784)	(144,872)	-
Issuance of long-term debt	139,524	23,397	139,947
Retirement of long-term debt	(334,840)	(147,544)	(77,873)
Net change in short-term borrowing	75,000	(69,820)	(64,138)
Net cash used for continuing financing activities	(245,628)	(428,990)	(86,241)
Net cash provided by (used for) discontinued financing activities	(608)	6,594	(2,538)
Net cash used for financing activities	(246,236)	(422,396)	(88,779)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(435,990)	544,291	7,346
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	554,407	10,116	2,770
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 118,417	$554,407	$ 10,116
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid during the year for:			
Income taxes, net of refunds	$ 198,282	$213,362	$ 90,663
Interest	46,709	53,273	67,777

The accompanying notes are an integral part of these financial statements.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
COMMON STOCK:			
Balance at beginning of year	$ 557,901	$ 702,511	$ 694,561
Issuances (149,834; 100,857; and 663,622 shares)	2,384	357	7,950
Reacquired capital stock (1,933,900 and 4,682,100 shares)	(60,784)	(144,872)	-
Premium on capital stock	-	(95)	-
Balance at end of year	499,501	557,901	702,511
RETAINED EARNINGS AND OTHER SHAREHOLDERS' EQUITY:			
Balance at beginning of year	488,975	430,309	356,327
Net income	199,491	150,346	165,620
Dividends on common stock (60 cents per share for 2000 and 80 cents per share for 1999 and 1998)	(62,426)	(88,155)	(88,008)
Dividends on preferred stock	(3,690)	(3,690)	(3,690)
Other	1,768	165	60
Balance at end of year	624,118	488,975	430,309
ACCUMULATED OTHER COMPREHENSIVE LOSS:			
Balance at beginning of year	(17,659)	(20,717)	(13,354)
Net income	199,491	150,346	165,620
Foreign currency translation adjustments	17,625	3,058	(7,363)
Total comprehensive income	217,116	153,404	158,257
Deduct net income included in comprehensive income	(199,491)	(150,346)	(165,620)
Other comprehensive income (loss)	17,625	3,058	(7,363)
Balance at end of year	(34)	(17,659)	(20,717)
UNALLOCATED STOCK HELD BY TRUSTEE FOR RETIREMENT SAVINGS PLAN:			
Balance at beginning of year	(20,401)	(23,298)	(25,945)
Distributions	3,174	2,897	2,647
Balance at end of year	(17,227)	(20,401)	(23,298)
PREFERRED STOCK	57,654	57,654	57,654
TOTAL SHAREHOLDERS' EQUITY AT END OF YEAR	$1,164,012	$1,066,470	$1,146,459

The accompanying notes are an integral part of these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

❑ BASIS OF ACCOUNTING

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

❑ 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 2000 presentation. We now classify all earnings from our unconsolidated investments in "Other income – net." We previously reported these earnings separately in revenues under "Earnings from unconsolidated investments" and have reclassified all amounts from prior periods to reflect this change. These reclassifications had no material effect on our previously reported consolidated financial position, results of operations, or cash flows.

❑ CONSOLIDATION PRINCIPLES

The consolidated financial statements include accounts and results of our wholly owned subsidiaries. We have eliminated significant intercompany balances and transactions. We account for our significant telecommunications and independent power investments using the equity method, because we exercise significant influence over those operations.

Prior to 2000, we consolidated the accounts of certain oil and natural gas operations for fiscal years ending in November to facilitate the timely preparation of the consolidated financial statements. Beginning in the first quarter of 2000, the one-month lag in reporting for these operations was eliminated. The December 1999 results of operations for these entities, which would have previously been reported in results of the first quarter of 2000, were recorded as an adjustment to beginning retained earnings as of January 1, 2000. This adjustment increased retained earnings by approximately $1,500,000. We consider this amount to be immaterial to our consolidated financial position, results of operations, or cash flows.

❑ CASH AND CASH EQUIVALENTS AND TEMPORARY INVESTMENTS

We consider all liquid investments with original maturities of three months or less to be 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 approximates the value reported on the Consolidated Balance Sheet. We had no temporary investments at December 31, 2000.

❑ ACCOUNTS RECEIVABLE

Accounts receivable are presented net of allowance for doubtful accounts of $11,456,000 in 2000 and $2,105,000 in 1999.

❑ PROPERTY, PLANT, AND EQUIPMENT

The following table provides year-end balances of the major classifications of our property, plant, and equipment, which we record at cost:

	December 31 2000	December 31 1999
	(Thousands of Dollars)	
UTILITY PLANT:		
Electric:		
Generation (including our share of jointly owned)	$ 54,476	$ 53,453
Transmission	412,885	405,061
Distribution	604,070	573,531
Other	135,477	94,698
Natural Gas:		
Production and storage	71,681	73,959
Transmission	167,416	163,968
Distribution	151,039	147,764
Other	39,841	30,693
Total Utility	1,636,885	1,543,127
Less: Accumulated depreciation, depletion, and amortization	553,274	494,235
	1,083,611	1,048,892
NONUTILITY PROPERTY, PLANT, AND EQUIPMENT:		
Telecommunications:		
Buildings and structures	8,382	3,762
Fiber optic network	90,925	48,503
Communications equipment	176,329	53,128
Construction work-in-progress	352,445	128,994
Other - telecommunications	18,491	3,470
Total telecommunications	646,572	237,857
Coal	-	240,227
Oil and Natural Gas	-	432,806
Other	6,401	64,459
Total Nonutility	652,973	975,349
Less: Accumulated depreciation, depletion, and amortization	39,798	319,506
	613,175	655,843
Total Utility and Nonutility Property, Plant, and Equipment, net of accumulated depreciation, depletion, and amortization	$ 1,696,786	$1,704,735

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 Federal Energy Regulatory Commission (FERC). This rate averaged 8.6 percent for 2000, 7.1 percent for 1999, and 8.3 percent for 1998. In addition, we capitalized interest of approximately $4,317,000 in connection with various telecommunications projects during 2000. This amount is included in telecommunications property, plant, and equipment in the table above.

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 recognize gain or loss upon the sale or other disposition of nonutility property. 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.

Included in the plant classifications are utility plant under construction in the amounts of $2,637,000 and $3,876,000 for 2000 and 1999, respectively, and coal and oil and natural gas plant under construction in the amount of

$5,729,000 for 1999. In our telecommunications operations, we classify costs associated with uncompleted portions of our fiber optic network as construction work in progress and, upon completion, classify the costs as network systems. For joint-build construction contracts, we record the total costs of construction reduced by reimbursements received, resulting in a net cost of the asset constructed. We record exchanges of fiber-use rights as the cost of the asset transferred plus any cash paid or, alternatively, as the cost of the asset transferred less any cash received.

For information on the October 31, 2000 sale of our oil and natural gas businesses and the pending sale of our coal businesses, see Note 2, "Decision to Sell Energy Businesses."

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 3.5 percent for 2000 and 3.0 percent for 1999 and 1998. We depreciate and amortize our telecommunications property, plant, and equipment on a straight-line basis over the estimated useful lives of the assets as follows:

Classification	Years
Buildings and structures	30
Fiber optic network	20
Communications equipment	10
Office furniture and equipment	3-5
Other – telecommunications	3-5

Our nonutility oil and natural gas operations used the successful-efforts method of accounting for exploration and development costs.

❑ JOINTLY OWNED ELECTRIC PLANT

Prior to the sale of the electric generating assets discussed in Note 5, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets," we were a joint-owner of Colstrip Units 1, 2, and 3. We owned 50 percent of Units 1 and 2 and 30 percent of Unit 3. We continue to own a leasehold interest in 30 percent of Colstrip Unit 4. We also own an approximate 30-percent interest in the transmission facilities serving these units. At December 31, 2000, our investment in these facilities was $132,331,000 and the related accumulated depreciation was $48,103,000.

Each joint-owner provides its own financing. Our share of direct expenses associated with the operation and maintenance of these joint facilities, including Colstrip Units 1, 2, and 3 through December 17, 1999, is included in the corresponding operating expenses in the Consolidated Statement of Income.

❑ INTANGIBLES

The following table provides year-end balances of the major classifications of intangibles:

	December 31	
	2000	**1999**
	(Thousands of Dollars)	
Telecommunications acquisition ...	$ 145,634	$ -
Goodwill	8,559	-
Other	3,957	1,239
Total intangibles	158,150	1,239
Less: Accumulated amortization ..	5,741	317
Total intangibles, net of accumulated amortization	$ 152,409	$ 922

For details on the intangibles recorded in conjunction with the telecommunications acquisition, see Note 4, "Acquisition of Telecommunications Properties." The excess of the January 2000 purchase price over the net assets of One Call Locators, Ltd. was recorded as goodwill and is being amortized over 15 years. Most other intangibles are being amortized over 5 years.

❑ RECLAMATION FUND

Under the current Colstrip Units 3 and 4 coal supply agreement, we maintain a reclamation fund representing restricted cash necessary to meet our estimated reclamation obligation at Western Energy for Units 3 and 4. We invest the funds required for these reclamation obligations until we need them to perform reclamation. At December 31, 2000, we had the funds invested entirely in a money market account. We regularly accrue an expense and an offsetting liability associated with our reclamation obligation. The reclamation fund is not offset against our accumulated liability, and both items are included in "Investment in discontinued coal operations" on the December 31, 2000 Consolidated Balance Sheet.

❑ REVENUE AND EXPENSE RECOGNITION

We record operating revenues monthly on the basis of consumption or service rendered. To match revenues with associated expenses, we accrue unbilled revenues for electric, natural gas, and telecommunication services delivered to customers but not yet billed at month-end. Our telecommunications service revenues are comprised of network services (wholesale and dedicated business line) revenues and retail sales (commercial and consumer long-distance) revenues. In conjunction with our efforts to expand our fiber optic network, we entered into agreements to grant and exchange fiber-use rights, principally through IRU agreements. Prior to July 1, 1999, we recognized revenues of fiber-use rights that qualified for sales-type lease accounting at the time of delivery and acceptance of the dark fiber by the customer. For those transactions, we determined cost of revenue by allocating the total estimated costs of the network to the specific fibers granted to the customer.

On July 8, 1999, the FASB issued Interpretation No. 43, "Real Estate Sales," which is an interpretation of SFAS No. 66, "Accounting for Sales of Real Estate." Effective July 1, 1999, therefore, we changed our revenue recognition policy. This interpretation was effective for transactions entered into after June 30, 1999, and requires entities to recognize revenues on fiber-use right agreements, or similar agreements, over the period of the agreement rather than at the time of execution if title to the fiber does not transfer to the customer by the end of the agreement term. In granting fiber-use rights, therefore, we record these transactions as operating leases and recognize revenues over the term of the agreement. The effect of this change in accounting resulted in approximately $7,000,000 of revenues that we did not record in 1999 from fiber-use right transactions entered into after June 30, 1999. Net income for 1999 would have been approximately $4,200,000 higher and both basic and diluted earnings per share would have been $0.03 higher if we were not required to make this accounting change.

The Emerging Issues Task Force (EITF) Issue No. 98-10 requires that energy contracts entered into under "trading activities" be marked to market with the gains or losses shown net in the income statement. EITF 98-10 is effective for fiscal years beginning after December 15, 1998. We adopted EITF 98-10 as of January 1, 1999, and accordingly mark to market energy contracts that qualify as "trading activities." The cumulative effect of adopting EITF 98-10 had no material effect on our consolidated financial position, results of operations, or cash flows.

For a discussion of Staff Accounting Bulletin (SAB) No. 101, "Revenue Recognition in Financial Statements," see Note 16, "New Accounting Pronouncements."

❑ 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. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded.

	December 31			
	2000		1999	
	Assets	**Liabilities**	**Assets**	**Liabilities**
	(Thousands of Dollars)			
Income taxes	$ 58,452	$ -	$ 57,526	$ -
Colstrip Unit 3 carrying charge	38,337	-	38,494	-
Conservation programs	27,956	-	28,378	-
Competitive transition charges (CTCs)	50,965	-	53,768	-
Generation net proceeds in excess of book value	-	214,887	-	219,726
Proceeds from oil and natural gas sale	-	32,549	-	-
Investment tax credits	-	13,163	-	13,330
Other	40,384	18,816	44,646	12,178
Subtotal	216,094	279,415	222,812	245,234
Less:				
Current portions	13,237	34,979	11,788	3,402
Total	$202,857	$244,436	$211,024	$241,832

Income taxes reflect the effects of temporary differences that we will recover in future rates. In August 1985, the 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. Conservation programs represent our Demand Side Management programs, which are in rate base and which we were amortizing to income over a 10-year period. We are recovering the CTCs, which relate to natural gas properties that we removed from regulation on November 1, 1997, through rates over 15 years. Investment tax credits and account balances included in "Other" represent items that we are amortizing currently or are subject to future regulatory confirmation.

With the sale of the electric generating assets, it is our position that any of these amounts related to electric supply should be recovered from sale proceeds in excess of book value. Amortization of these assets stopped in February 2000 when the expenses were removed from rates. For further information on the effects of the sale of our electric generating assets, see Note 5, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

❑ 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. The reserves' balance at December 31, 2000 was approximately $11,080,000 and at December 31, 1999 was approximately $11,166,000. We have included these reserves in "Current liabilities" on the Consolidated Balance Sheet.

❑ INCOME TAXES

We and our United States subsidiaries file a consolidated United States income tax return. We allocate consolidated United States income taxes to utility and nonutility operations as if we filed separate United States income tax returns for each operation. 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 Note 6, "Income Tax Expense."

❑ DEFERRED REVENUES

We defer revenues to account for the timing differences between cash received and revenues earned and reflect these amounts on the Consolidated Balance Sheet in "Deferred revenue." We reflect the current portion of these amounts in "Current portion of deferred revenue" on the Consolidated Balance Sheet. We are recognizing the prepayment received in January 1999 from a telecommunications customer and the payment received in December 1999 from the Los Angeles Department of Water and Power in revenues over the original terms of the agreements, approximately 11 years in each case.

❑ NET INCOME PER SHARE OF COMMON STOCK

We compute basic net income per share of common stock for each year based upon the weighted average number of common shares outstanding. In accordance with SFAS No. 128, "Earnings per Share," diluted net income per share of common stock reflects the potential dilution that would occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that shared in our earnings.

For comparative purposes, the following table shows consolidated basic net income per share.

	Year Ended December 31		
	2000[1]	**1999**	**1998**
Continuing Operations	$0.69	$0.86	$1.11
Discontinued Operations ...	1.17	0.48	0.36
Consolidated	$1.86	$1.34	$1.47

[1] 2000 "Discontinued Operations" figures include gain on sale of discontinued oil and natural gas operations.

- **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 we may not recover the carrying amount of an asset.

- **COMPREHENSIVE INCOME**

Comprehensive income consists of net income and other comprehensive income (loss). For the years ended December 31, 2000, 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 $17,625,000 and $3,058,000 in 2000 and 1999 and a decrease of $7,363,000 in 1998.

Nearly all of the 2000 increase resulted from the sale of the Canadian subsidiaries of our former oil and natural gas businesses. In accordance with SFAS Nos. 52, "Foreign Currency Translation," and 130, "Reporting Comprehensive Income," we recognized the cumulative translation loss associated with those subsidiaries and included it in the computation of the gain on the October 31, 2000 sale of the oil and natural gas businesses. Including it reduced our gain by approximately $21,200,000. Because the translation adjustment was not part of the tax basis of the foreign subsidiaries' properties, it did not affect the calculation of taxes on the sale.

- **DERIVATIVE FINANCIAL INSTRUMENTS**

As discussed in Note 2, "Decision to Sell Energy Businesses," in the "October 31, 2000 Divestiture of Oil and Natural Gas Businesses and Pending Divestiture of Remaining Energy Businesses" section, we sold all of the stock of our oil and natural gas businesses on October 31, 2000, including MPT&M, which engaged in trading activities. At that time, we were using derivative financial instruments to reduce earnings volatility and stabilize cash flows by hedging some of the price risk associated with our nonutility energy commodity-producing assets, contractual commitments for firm supply, and natural gas transportation agreements. Now, however, we use these derivative financial instruments only as discussed below.

Electric Swap Agreements

Long-term power supply agreements, primarily one with a large industrial customer, expose us to commodity price risk. We are exposed to this risk to the extent that a portion of the electric energy we are required to sell to our industrial customers at fixed rates is purchased at prices indexed to a wholesale electric market, which can be higher than the fixed sales rate that we receive pursuant to our power supply agreements. We mitigate our exposure to losses on these agreements with financial derivative instruments called "price swaps" and offsetting electric energy purchase and sales agreements.

Since June 1998, we have had a price swap agreement with one of our industrial customers that converts 43 MWs of the Mid-Columbia (Mid-C) index price of our supply agreement with that customer to a fixed price through May 2001. In fiscal year 2000, we also entered into another price swap with a counterparty that effectively hedges 35 MWs of the anticipated market-based purchases to supply that agreement through March 2001.

In accordance with the provisions of SFAS No. 80, "Accounting for Futures Contracts," we recognized gains and losses from the financial swaps in the same period in which we recognized the sales and related purchases under that agreement. For fiscal year 2000, we recognized a net gain of approximately $16,000,000 from these financial swaps and losses of approximately $32,200,000 from supplying large industrial customers. For more specific information about the commodity price risk that we face as a result of our long-term power supply agreements, see Note 13, "Contingencies," in the "Long-Term Power Supply Agreements" section.

An estimate of the fair market value of the swaps based on the Mid-C forward prices of December 29, 2000 aggregated approximately $21,800,000 as of December 31, 2000, which would offset approximately 40 percent of the expected losses on the above power supply agreements. For information on SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and how we expect it to affect us, see Note 16, "New Accounting Pronouncements."

Natural Gas Utility Swaps

By drilling wells and adding compression at our Cobb storage reservoir, we are able to sell natural gas that had been held in reserve to provide firm storage deliverability to our customers. We therefore contracted to sell, from October 2000 through March 2001, 1,760,000 dekatherms from that reservoir at a monthly price based on the Alberta Energy Company "C" Hub (AECO-C) index. To reduce our exposure to fluctuations of the market index price, we entered into a swap agreement with a counterparty that effectively converts that index price to a fixed price for 903,000 dekatherms associated with these sales from December 2000 through February 2001.

For December 2000, we recognized a loss of approximately $300,000 on the swap and a profit of approximately $1,200,000 on the sale of the Cobb storage natural gas. Based on the AECO-C forward prices at December 29, 2000, we estimate a loss of approximately $3,000,000 on the swap to offset profits of $4,900,000 on the sale through February 2001. We are deferring the expected net profit of these transactions in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," until the PSC approves its inclusion in future rate schedules.

Continental Energy Operations

Continental Energy had investments in independent power partnerships, some of which had entered into derivative financial instruments to hedge interest rate exposure on floating-rate debt and natural gas price fluctuations. We believe that, as of December 31, 2000, we had not been exposed to any material adverse effects from the risks inherent in these instruments.

- **FAIR VALUE OF FINANCIAL INSTRUMENTS**

	2000		1999	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
	(Thousands of Dollars)			
ASSETS:				
Investment in independent power project (cost basis only)	$ 3,107	$ 1,687	$ 3,504	$ 1,641
Reclamation fund	46,043	46,043	43,460	43,460
Other significant investments	40,084	43,799	52,523	55,689
LIABILITIES:				
Company obligated mandatorily redeemable preferred securities	$ 65,000	$ 65,000	$ 65,000	$ 63,206
Long-term debt (including due within one year)	482,481	482,866	677,467	655,652

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

- Investment in independent power project - The fair value represents our assessment of the present value of net future cash flows embodied in this investment, discounted to reflect current market rates of return.

- Reclamation fund and other investments - The carrying value of most of the investments approximates fair value as the investments have short maturities or the carrying value equals their cash surrender value. Fair value for the remainder of the investments was estimated based on the discounted value of the future cash flows expected to be received using a rate of return expected on similar current investments. The reclamation fund is included in "Investment in discontinued operations" on the Consolidated Balance Sheet at December 31, 2000. Other significant investments consist mainly of the cash value of insurance policies associated with an unfunded, nonqualified benefit plan for senior management executives and directors and funds deposited with the trustee of our securitization bonds discussed in Note 10, "Long-Term Debt."

- Mandatorily redeemable preferred securities and long-term debt - The fair value was estimated using quoted market rates for the same or similar instruments. Where quotes were not available, fair value was estimated by discounting expected future cash flows using year-end incremental borrowing rates. Long-term debt for 2000 includes amounts reported in "Investment in discontinued operations" on the Consolidated Balance Sheet.

NOTE 2 – DECISION TO SELL ENERGY BUSINESSES

On March 28, 2000, after a careful review of options and strategies, our Board of Directors announced that we would begin the process of divesting our multiple energy businesses, separating them from Touch America. Following the merger and the sale of the utility business to NorthWestern, Touch America expects to use the cash proceeds from the sale of the oil and natural gas businesses, the coal businesses, the independent power production business, and the utility business to take advantage of opportunities in the telecommunications business. We expect these gross cash proceeds, before income taxes and transaction costs, to total approximately $1,300,000,000.

❑ **CONTINUING/DISCONTINUED OPERATIONS**

As a result of our restructuring efforts, we have evaluated our operations to determine which segments should be included in continuing or discontinued operations. Because the sale of our utility business remains subject to shareholder approval, we have included the results of operations, financial position, and cash flows of our electric (including Colstrip Unit 4) and natural gas utility business in continuing operations. We plan to schedule a special meeting of our shareholders in the second or third quarter 2001 to consider and vote on the sale and other matters.

We have not afforded Continental Energy discontinued operations accounting treatment since we have historically reported Colstrip Unit 4 with Continental Energy as the Independent Power Group segment. Although we sold Continental Energy on February 21, 2001, the sale of our utility business includes Colstrip Unit 4. Consequently, we have reflected Continental Energy activity in continuing operations for all periods presented.

As a result of our Board of Directors' approval to enter into definitive agreements with respect to our former oil and natural gas and our coal operations, we have applied discontinued operations accounting treatment to these operations, effective August 22, 2000 for our oil and natural gas operations and September 14, 2000 for our coal operations. The results of this treatment are the following:

- We have separately reported income after income taxes from oil and natural gas and coal operations in income from discontinued operations for all periods presented to reflect the reclassification of these operations as discontinued.

- We sold our oil and natural gas operations on October 31, 2000, and therefore, balances related to these operations are not reflected on our December 31, 2000 Consolidated Balance Sheet. Net assets and liabilities of our discontinued coal operations are included in "Current assets," under "Investment in discontinued operations" in our December 31, 2000 Consolidated Balance Sheet. At December 31, 2000, we owned total assets related to our discontinued coal operations of approximately $282,129,000.

- We have reported cash flows of oil and natural gas and coal operations as "net cash provided by (used for) discontinued operations," segregated by operating, investing, and financing activities.

The following table presents revenues separately for our discontinued oil and natural gas and coal operations:

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
Oil and Natural Gas Operations..	$ 348,698	$ 355,532	$ 239,268
Coal Operations................	224,515	236,782	216,757

- **SALE OF OIL AND NATURAL GAS OPERATIONS**

On August 25, 2000, our wholly owned subsidiary, Entech, and Altana Exploration Company, Entech's wholly owned subsidiary, entered into a Stock and Asset Purchase Agreement with PanCanadian Petroleum Limited (PanCanadian Petroleum) and one of PanCanadian Petroleum's wholly owned subsidiaries, PanCanadian Energy, Inc. (PanCanadian Energy). Pursuant to the Stock and Asset Purchase Agreement, PanCanadian Petroleum agreed to purchase from us all of the stock and assets of our Canadian oil and natural gas businesses, and PanCanadian Energy agreed to purchase from us all of the stock of our United States oil and natural gas businesses. (We collectively refer to PanCanadian Petroleum and PanCanadian Energy as PanCanadian.) The transaction closed on October 31, 2000, with a purchase price of US$475,000,000, subject to post-closing adjustments.

As a result of the transaction, we recorded a gain in the fourth quarter 2000 of approximately $62,000,000, net of income taxes and a regulatory liability of approximately $32,500,000. The $32,500,000 liability represents the portion of the proceeds from the sale of oil and natural gas businesses to PanCanadian attributable to properties previously in the natural gas utility's rate base. Based on gas stipulation agreements addressing the removal of natural gas production properties from regulation, we have agreed to share this amount with our natural gas utility ratepayers.

- **SALE OF CONTINENTAL ENERGY**

On September 19, 2000, Entech entered into a Stock Purchase Agreement with BBI pursuant to which BBI agreed to purchase the stock of Continental Energy, our remaining independent power production business. In January 2001, BBI assigned its right to purchase Continental Energy to BBI's wholly owned subsidiary, CES Acquisition Corp. The transaction closed on February 21, 2001, with a purchase price of $84,500,000, subject to post-closing adjustments. Based on the net book value of Continental Energy, we expect to record a gain in the first quarter 2001 of approximately $33,000,000, net of income taxes.

- **STATUS OF SALES OF REMAINING ENERGY BUSINESSES**

Pending Sale of Coal Operations

On September 15, 2000, Entech entered into a Stock Purchase Agreement with Westmoreland pursuant to which Westmoreland agreed to purchase the companies comprising our coal businesses. The purchase price is $138,000,000, subject to customary closing adjustments. We expect this transaction to close at approximately the beginning of the second quarter 2001 and, based on the net book value of our coal operations, we expect to record a gain on the sale.

The Montana Power L.L.C./Utility Business

On September 29, 2000, we entered into a Unit Purchase Agreement with NorthWestern Corporation, a South Dakota-based energy company, pursuant to which NorthWestern agreed, as discussed below, to purchase our affiliate, The Montana Power L.L.C., a Montana limited liability company (MPLLC). MPLLC will hold – among other assets, liabilities, commitments, and contingencies - our electric (including Colstrip Unit 4) and natural gas utility business. The consideration for MPLLC is approximately $1,090,000,000, and is comprised of cash of $602,000,000 and NorthWestern's assumption of up to $488,000,000 of our debt.

The transaction is targeted to close approximately three months after the proxy statement/prospectus is filed and becomes effective. The closing is subject to the approval of our shareholders, regulatory approvals from the PSC, and other customary conditions. We received approval for the sale from FERC in February 2001. We can provide no assurance that the transaction will close or, if it does, that the terms and conditions will remain unchanged.

For additional information on the special meeting of our shareholders to consider and vote on the sale and other matters, see Note 3, "Upcoming Special Meeting of Shareholders."

NOTE 3 – UPCOMING SPECIAL MEETING OF SHAREHOLDERS

Our Board of Directors has approved a merger that will create a new company, Touch America Holdings, Inc., to own what is today our telecommunications business. Immediately following this merger, our remaining energy business – consisting of our electric and natural gas utility – will be sold to NorthWestern. On completion of this merger and the sale of the utility business to NorthWestern, Touch America Holdings will own Touch America, Inc. and Tetragenics Company, which together will constitute its telecommunications operating business.

On completion of the merger, our shareholders will be deemed to receive one share of Touch America Holdings' common stock for each common share of The Montana Power Company, and one share of Touch America Holdings' Preferred Stock, $6.875 Series, for each share of The Montana Power Company's outstanding Preferred Stock, $6.875 Series.

We will hold a special meeting of our shareholders to consider and vote on the merger and the sale of the utility business to NorthWestern. In addition, shareholders of our common stock will be asked to vote in favor of the redemption of The Montana Power Company's outstanding Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series. If the redemption of the preferred stock is not approved by at least a majority of all of our common shareholders, each shareholder of The Montana Power Company's Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series, will be deemed to receive in the merger one share of Touch America Holdings' Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series, for each outstanding share of The Montana Power Company's Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series, respectively. We plan to schedule this special meeting of our shareholders for the second or third quarter 2001.

NOTE 4 – ACQUISITION OF TELECOMMUNICATIONS PROPERTIES

On June 30, 2000, in accordance with a previously executed stock purchase agreement, we acquired wholesale, private line, long-distance, and other telecommunications services in the former U S WEST fourteen-state region from Qwest for approximately $206,000,000, subject to post-closing adjustments. We estimate that Touch America's related capital expenditures, mainly to install electronics on new routes, will be an additional $70,000,000. The fourteen-state region covers approximately 250,000 customer accounts for voice, data, and video services. Touch America also acquired a fiber optic network of approximately 1,800 route miles and associated electronics and switches that will connect to Touch America's existing fiber optic network. As a result of the acquisition, 173 sales and sales-support personnel in the fourteen-state region became employees of Touch America.

We accounted for the acquisition using the purchase method of accounting. As a result, we have allocated our cost of the acquisition to the assets acquired and liabilities assumed based on our estimates of their fair values as of the June 30, 2000 acquisition date. Accordingly, we recorded approximately $60,000,000 of property and equipment and approximately $146,000,000 of intangible assets related to this acquisition. We are amortizing the acquired property and equipment and intangible assets over their estimated useful lives on the straight-line basis in accordance with our stated policies.

We have received an appraisal of the acquired properties from an independent third party. We used this appraisal as a basis for recognizing the acquired assets and the depreciation and amortization in our consolidated financial statements. The balances reflected in our Consolidated Balance Sheet and related depreciation or amortization periods are as follows:

	Asset Balances	**Depreciation or Amortization Periods**
	(Thousands of Dollars)	(Years)
Tangible Assets:		
Furniture and equipment	$ 600	3-5 years
Network assets – fiber	9,200	20 years
Network assets – optical electronics	50,448	10 years
Total Tangible Assets	$ 60,248	
Intangible Assets:		
Assembled workforce	$ 1,900	5 years
Customer base – wholesale	15,300	5 years
Customer base - commercial	3,200	3 years
IRU capacity agreement	125,234	20 years
Total Intangible Assets	$145,634	

The accounts of this acquisition have been included in our consolidated accounts since June 30, 2000.

The following table presents the summarized consolidated results of operations for the years ended December 31, 2000 and 1999 on an unaudited, pro forma basis as though this June 30, 2000 acquisition had occurred as of January 1, 1999:

	Pro Forma Consolidated Results of Operations (Unaudited)	
	2000	**1999**
	(Thousands of Dollars) (except per-share amounts)	
Revenues	$1,154,735	$1,068,425
Net Income from Continuing Operations	94,481	129,231
Net Income Available for Common	214,089	177,466
Earnings per share:		
Basic	$ 2.03	$ 1.62
Diluted	$ 2.01	$ 1.61

NOTE 5 – DEREGULATION, REGULATORY MATTERS, AND 1999 SALE OF ELECTRIC GENERATING ASSETS

❑ DEREGULATION

The electric and natural gas utility businesses in Montana are transitioning to a competitive market in which commodity energy 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. In October 2000, the PSC issued a Request for Comments on Extension of Transition Period. In December 2000, due to the lack of a competitive market for the supply of electric energy in Montana, the PSC extended the transition period two years, until July 1, 2004. Pursuant to the Electric Act, the electric utility is required to supply electric energy for the additional two-year period, and we are working with the Montana Legislature and the PSC to fully recover the default supply costs.

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. We have opened access on our gas transmission and distribution systems and all of our natural gas customers have the opportunity of gas-supply choice.

Electric

Residential accounts previously in the competitive market largely returned to regulated supply in the fourth quarter 2000. Some industrial loads have curtailed operations due to high supply costs in the competitive market, reducing our electric load.

As required by the Electric Act, we filed a comprehensive transition plan with the PSC in July 1997. On July 1, 1999, we filed a case with the PSC to resolve the remaining Tier II issues under the filing. Tier II issues address the recovery and treatment of the Qualifying Facility (QF) power-purchase contract costs; regulatory assets associated with the electric generating business; and a review of our electric generating assets sale, including the treatment of sale proceeds above the book value of the assets.

In implementing our comprehensive transition plan, we initiated litigation in Montana District Court in Butte to address our ability to use tracking mechanisms to ensure fair and accurate recovery of above-market QF costs and certain other transition costs. We also sought court clarification on whether the Electric Act authorized a rate freeze, which means that rates cannot change, or a rate cap, which means that rates cannot increase more than a certain level, during the initial transition period that ends July 1, 2002.

In May 2000, the district court ruled that the PSC must allow us to incorporate tracking mechanisms in our transition plan proposal and that the Electric Act authorized a rate cap. The PSC and the Large Customer Group appealed to the Montana Supreme Court the court's decision regarding tracking mechanisms, and we did not appeal its decision regarding the rate cap. The parties completed briefing of the tracking-mechanisms issue in October 2000 and are awaiting a decision from the Montana Supreme Court, which has requested amicus briefs and will schedule oral argument.

After the district court case, we updated our Tier II filing to reflect the closing of the sale of our electric generating assets. The PSC has suspended the procedural schedule pending a resolution from the Montana Supreme Court and, therefore, we do not expect an order from the PSC until the third or fourth quarter 2001.

Natural Gas

Through December 31, 2000, approximately 240 natural gas customers with annual consumption of 5,000 dekatherms or more – 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.

❑ REGULATORY MATTERS

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

Our natural gas transportation pipelines are generally not subject to FERC jurisdiction. We conduct limited interstate transportation subject to FERC jurisdiction, but FERC has allowed the PSC to set the rates for this interstate service. Our natural gas storage and distribution services, as well as our intrastate transportation services, are subject to PSC jurisdiction.

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

FERC

On March 30, 1998, we submitted a cost-of-service filing with FERC to increase our open access transmission rates and the rates for bundled wholesale electric service to two rural electric cooperatives. Effective November 1, 1998, FERC approved an interim increase in rates charged for transmission service. In May 2000, we received final approval from FERC.

Through a stranded-costs filing with FERC in April 2000, we are seeking recovery of approximately $23,800,000 in transition costs associated with serving both of the wholesale electric cooperatives. We do not expect a FERC decision on this filing, which corresponds with our transition-costs recovery proceedings with the PSC in Montana, until after the PSC issues its order.

PSC

In January 2000, as a result of the sale proceeds from the sale of our electric generating assets exceeding the book value of the assets sold, we filed a voluntary rate reduction with the PSC for approximately $16,700,000 annually. This reduction became effective February 2, 2000.

The Electric Act established a rate cap for all electric customers pursuant to which transmission and distribution rates could not be increased until July 1, 2000. On August 11, 2000, with the expiration of the Electric Act's cap, we filed a combined rate case with the PSC, seeking increased electric and natural gas rates. We requested increased annual electric transmission and distribution revenues of approximately $38,500,000, with a proposed interim annual increase of approximately $24,900,000. On November 28, 2000, the PSC granted us an interim electric rate increase of approximately $14,500,000, with hearings on this submission held in late January and early February 2001. We expect a decision from the PSC during the second quarter 2001.

On August 25, 2000, we filed a request for increased rates to recover approximately $9,200,000 of higher power-supply costs relating to certain QF costs on an interim basis, pending final determination of QF transition costs. In a PSC work session in October 2000, the PSC denied our request. We sought reconsideration of the PSC's order, but the PSC also denied this request in January 2001. We have decided not to appeal this decision.

In accordance with our October 31, 1998 Asset Purchase Agreement with PPL Montana, as amended June 29, 1999 and October 29, 1999, we expect to sell our portion of the 500-kilovolt transmission system associated with Colstrip Units 1, 2, and 3 for $97,100,000. We expect this transaction to close in 2001. The after-tax proceeds that we expect to receive as a result of this transaction will remain with The Montana Power L.L.C.

Natural Gas/PSC

On January 19, 2001, we submitted with the PSC an Annual Gas Cost Tracker for an increase of approximately $51,000,000 and a Compliance Filing resulting from the sale of gathering and production properties previously in the natural gas utility's rate base for a credit of approximately $32,500,000. This resulted in a net increase of approximately $18,500,000 in revenues effective February 1, 2001. See Note 2, "Decision to Sell Energy Businesses," under the "Sale of Oil and Natural Gas Operations" section, for further information on the $32,500,000 credit to our natural gas utility ratepayers.

As discussed above, we submitted a combined filing with the PSC on August 11, 2000, seeking increased natural gas and electric rates. We requested increased annual natural gas revenues of approximately $12,000,000, with a proposed interim annual increase of approximately $6,000,000. On November 28, 2000, the PSC granted us an interim natural gas rate increase of approximately $5,300,000, with hearings on this submission held in late January and early February 2001. We expect a decision from the PSC during the second quarter 2001.

On August 12, 1999, we filed a natural gas rate case with the PSC requesting increased annual revenues of $15,400,000, with a proposed interim increase of $11,500,000. An interim increase of $7,600,000 became effective on December 10, 1999, and a final PSC order that became effective on April 1, 2000 approved an additional increase of $2,800,000.

- **1999 SALE OF ELECTRIC GENERATING ASSETS**

Assets Sold

On December 17, 1999, in accordance with the Asset Purchase Agreement entered into with PPL Montana, we sold substantially all of our electric generating assets and related contracts. We also sold an immaterial amount of associated transmission assets, totaling less than 40 miles. The asset sale did not include the Milltown Dam near Missoula, Montana (gross capacity of approximately 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.

As expected, the sale of our electric generating assets in December 1999 reduced the utility's net income for 2000. Utility revenues decreased because of discontinued off-system revenues that related to the electric generating assets sold. In addition, we no longer earn a return on our shareholders' investment in the electric generating assets. Before the sale, revenues covered the costs of operating the generating plants, taxes and interest, and earned a return on our shareholders' investment. Since the sale, we continue to bill our core customers for energy supply, but now these revenues recover the costs of the power that we purchase to serve these customers. The energy that we formerly generated and sold to core customers is now purchased pursuant to buyback contracts. The maximum price that we pay for power in the buyback contracts, $22.25/MWh, represents our net fully allocated supply costs of service in current rates, replacing operations and maintenance expense, property tax expense, depreciation expense, and return on investment associated with the electric generating assets.

In the sale of these assets, we generally retained all pre-closing obligations, and the purchaser generally assumed all post-closing obligations. However, with respect to environmental liabilities, the purchaser assumed all pre-closing (with certain limited exceptions) and post-closing environmental liabilities associated with the purchased assets.

While the purchaser assumed pre-closing environmental liabilities, we agreed to indemnify the purchaser from these pre-closing environmental liabilities, including a limited indemnity obligation for losses arising from required remediation of pre-closing environmental conditions, whether known or unknown at the closing, 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 aggregate amount no greater than 10 percent of the purchase price paid for the assets.

In December 2000, we received a claim notice related to this indemnity obligation. Based on available information, we do not expect this indemnity claim on the indemnity obligation to have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Cash Proceeds

At December 31, 1999, we recorded a regulatory liability and related deferred income tax to reflect the generation sale proceeds in excess of book value. The Company's current estimate of this liability, which will ultimately be determined in the Tier II docket, is approximately $215,000,000 before income taxes. This liability represents a deferral of the gain on the generation sale and nothing has been reflected in the Consolidated Statement of Income.

As part of our Tier II filing, we plan to deduct from the regulatory liabilities approximately $22,000,000 of other generation-related transition costs and approximately $65,600,000 of regulatory asset transition costs. The other generation-related transition costs consist mainly of 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.

We have used a portion of the net cash proceeds received (excluding the proceeds in excess of book value) to purchase shares of our common stock, to reduce debt, and to fund projects involving expansion of Touch America. 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." For additional information on Touch America's projects, see Note 14, "Commitments," in the "Telecommunications" section.

Effect on 1999 Earnings

The asset sale affected positively 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 ITCs.

NOTE 6 - INCOME TAX EXPENSE

Income before income taxes was as follows:

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
Income from continuing operations:			
United States	$ 108,855	$ 128,084	$ 192,059
Canada	237	-	-
Other countries	699	1,167	480
	109,791	129,251	192,539
Income from discontinued operations	192,241	65,158	51,255
	$ 302,032	$ 194,409	$ 243,794

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:

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
Computed "expected" income tax expense	$ 105,712	$ 68,043	$ 85,328
Adjustments for tax effects of:			
Statutory depletion	(2,535)	(3,440)	(4,156)
Tax credits	(4,792)	(25,775)	(4,722)
State income tax, net	6,178	4,545	7,393
Reversal of utility book/tax depreciation	4,119	5,318	2,784
Other	(6,141)	(4,628)	(8,453)
Actual income tax expense	$ 102,541	$ 44,063	$ 78,174

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

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
Current:			
United States	$ 136,938	$ 293,319	$ 88,233
Canada	13,669	1,710	1,212
Other countries	-	30	-
State	15,755	53,858	13,462
	166,362	348,917	102,907
Deferred:			
United States	(49,174)	(267,958)	(20,331)
Canada	(7,509)	9,930	(1,851)
Other countries	(18)	-	-
State	(7,120)	(46,826)	(2,551)
	(63,821)	(304,854)	(24,733)
	102,541	44,063	78,174
Less:			
Income tax expense attributable to discontinued operations	68,943	13,233	11,331
Income tax expense attributable to continuing operations	$ 33,598	$ 30,830	$ 66,843

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

	December 31	
	2000	**1999**
	(Thousands of Dollars)	
Plant related	$ 229,080	$ 321,383
Investment in nonutility generation projects	3,442	6,171
Other	42,834	44,520
Gross deferred tax liabilities	275,356	372,074
Coal reclamation	-	(48,096)
Amortization of gain on sale/leaseback	(10,969)	(11,649)
Deferred revenues	(99,319)	(103,578)
Investment tax credit amortization	(8,553)	(14,055)
Other	(195,672)	(204,152)
Gross deferred tax assets	(314,513)	(381,530)
Net deferred tax assets	(39,157)	(9,456)
Less current deferred tax assets - net	(17,738)	(18,303)
Total noncurrent deferred tax (assets) liabilities	$(21,419)	$ 8,847

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

	Thousands of Dollars
Change in noncurrent deferred tax	$ (29,701)
Regulatory assets related to income taxes	2,733
Current deferred tax assets - net	2,587
Amortization of investment tax credits	(167)
Coal deferred taxes reclassified to discontinued operations on Consolidated Balance Sheet	26,382
Other	(3,680)
	$ (1,846)
Discontinued operations deferred taxes	(61,975)
Deferred tax expense	$ (63,821)

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 earlier periods presented.

❑ SHARE REPURCHASE PROGRAM

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, 2000, we had 103,742,934 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.

Subsequent to this authorization, we entered into a Forward Equity Acquisition Transaction (FEAT) program with a bank that committed to purchase shares on our behalf. Under the terms of the program, the amount owed to the bank and the number of shares held by the bank cannot exceed certain limits. In March 2000, these limits were amended and now are $125,000,000 and 2,500,000 shares. The expiration date of the program is August 1, 2001. 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 plus 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 plus interest costs less dividends.

In December 1999, when the limits described above were $200,000,000 and 8,000,000 shares, we used proceeds from the sale of our generation assets to acquire 4,682,100 shares of our stock under the FEAT program. We purchased these shares at prices, including commissions, which ranged from $27.05 per share to $33.52 per share. The total cost was $144,872,000 for an average price of approximately $30.94 per share. In December 2000, we acquired an additional 1,933,900 shares of our stock under the program. The prices, including commissions, for these shares ranged from $27.26 per share to $33.53 per share and their total cost was $60,784,000 for an average price of approximately $31.43 per share. We have reflected the entire 6,616,000 shares purchased as treasury stock with a cost of $205,656,000 on the Consolidated Balance Sheet. As of March 16, 2001, the bank had acquired no further shares on our behalf.

❑ 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 its common shares with a minimum of $100 and a maximum of $60,000 per year.

In conjunction with the pending divestiture of our energy businesses and our transition to a telecommunications enterprise, our Board of Directors voted in October 2000 to eliminate the dividend payment on our common stock effective the first quarter 2001. The final quarterly dividend on our common stock was $0.20 per share, payable on November 1, 2000. The Board's decision did not affect dividends on our preferred stock.

❑ RETIREMENT SAVINGS PLAN

We have a 401(k) Retirement Savings Plan that covers 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 monthly to Plan participants to help meet the Company's matching obligation. 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, 2000, 2,756,662 shares had been allocated to the participants' accounts. We recognize expense for the Plan using the Shares Allocated Method, and the pretax expense was $4,267,000, $4,890,000, and $4,923,000 for 2000, 1999, and 1998, respectively.

❑ LONG-TERM 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.

During 1999, a grant of 12,000 shares of restricted stock was issued to an individual under the Long-Term Incentive Plan. The award is subject to forfeiture or proration if the individual should terminate employment. In May 2000, restrictions were removed on 4,000 of the shares granted. Earned awards are reflected as common stock on the Consolidated Balance Sheet and as compensation expense in the Consolidated Statement of Income over the period of required employment. At December 31, 2000, 8,000 shares of restricted stock remained.

Option activity is summarized below:

	2000		1999		1998	
	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
Outstanding, beginning of year	3,280,325	$25.63	2,548,094	$22.71	1,081,330	$11.00
Granted	1,199,545	34.36	919,510	32.14	2,234,658	24.50
Exercised	149,834	17.07	88,857	10.83	702,562	11.25
Cancelled	253,792	26.88	98,422	24.08	65,332	13.47
Outstanding, end of year	4,076,244	$28.43	3,280,325	$25.63	2,548,094	$22.71

Shares under option at December 31, 2000, 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	228,099	$11.05	5 yrs	228,099	$11.05
$18.00 to $23.06	472,999	19.48	8 yrs	383,446	18.64
$26.53 to $32.50	2,359,346	28.21	9 yrs	1,507,154	26.62
$35.36 to $38.69	1,015,800	37.00	9 yrs	258	35.36
	4,076,244			2,118,957	

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 2000, 1999, and 1998 was $16.35, $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 2000, 1999, and 1998, respectively: (1) risk-free interest rate of 6.05 percent, 6.35 percent, and 5.08 percent; (2) expected life of 6.2, 9.8, and 10 years; (3) expected volatility of 42.00 percent, 24.92 percent, and 19.34 percent; and (4) a dividend yield of zero percent, 5.97 percent, and 6.51 percent. Had we elected to use SFAS No. 123, compensation expense would have increased $11,827,000 in 2000, $5,280,000 in 1999, and $795,000 in 1998. The 2000 pro forma net income would be $188,632,000 with basic earnings per common share of $1.79 and diluted earnings per common share of $1.77. 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:

Series	Stated and Liquidation Price*	Shares Issued and Outstanding 2000	Shares Issued and Outstanding 1999	Thousands of Dollars 2000	Thousands of Dollars 1999
$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.

As discussed in Note 3, "Upcoming Special Meeting of Shareholders," we have asked our shareholders of common stock to vote in favor of the redemption of our outstanding Preferred Stock, $4.20 Series, and $6.00 Series. In addition, our Board of Directors will seek approval to redeem our Preferred Stock, $6.875 Series. We are not requesting our shareholders to take any action on this matter at this time.

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, 2000 and 1999, 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.

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. We also 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 (MTNs) and those securing Pollution Control Revenue Bonds.

Long-term debt consists of the following:

	December 31	
	2000	**1999**
	(Thousands of Dollars)	
First Mortgage Bonds:		
7 ½% series, due 2001	$ -	$ 25,000
7% series, due 2005	5,386	50,000
8 ¼% series, due 2007	365	55,000
8.95% series, due 2022	1,446	50,000
Secured Medium-Term Notes- maturing 2000-2025 7.20%-8.11%...........	28,000	88,000
Pollution Control Revenue Bonds:		
City of Forsyth, Montana		
6 1/8% series, due 2023..................	90,205	90,205
5.90% series, due 2023...................	80,000	80,000
Unsecured Medium-Term Notes:		
Series A – maturing 2000-2022 8.68%-8.80% .	-	17,000
Series B – maturing 2001-2026 7.05%-7.96% .	100,000	100,000
$400 Million Senior Secured Credit Facility..	100,000	-
Natural Gas Transition Bonds – 6.20%, due 2012	58,412	61,015
ESOP Notes Payable – 9.20%, due 2004.........	16,197	19,431
Revolving Credit Agreements..................	-	17,502
Other	1,365	28,111
Unamortized Discount and Premium.............	(2,859)	(3,797)
	478,517	677,467
Less: Portion due within one year...........	169,054	58,955
	$309,463	$618,512

On April 13, 2000, we retired, prior to maturity, $25,000,000 of our 7.5 percent First Mortgage Bonds (Bonds) due April 1, 2001.

On April 25, 2000, we offered to purchase any or all of the following series of our outstanding debt: 8.95 percent Bonds due February 1, 2022; 7.33 percent Secured MTNs due April 15, 2025; 8.11 percent Secured MTNs due January 25, 2023; 7.00 percent Bonds due March 1, 2005; and 8.25 percent Bonds due February 1, 2007. The total amount outstanding for these issues was $190,000,000 as of April 25, 2000. On May 24, 2000, we retired $182,803,000 of this amount, as follows:

- $44,614,000 of 7.00 percent Bonds due March 1, 2005;
- $54,635,000 of 8.25 percent Bonds due February 1, 2007;
- $48,554,000 of 8.95 percent Bonds due February 1, 2022;
- $20,000,000 of 7.33 percent Secured Series A MTNs due April 15, 2025; and
- $15,000,000 of 8.11 percent Secured Series A MTNs due January 25, 2023.

We retired two additional issues of Series A Secured MTNs during 2000. On January 13, 2000, we retired $5,000,000 of 7.25 percent notes due January 19, 2024, and on June 1, 2000, we retired at maturity $20,000,000 of 7.20 percent notes.

On January 14, 2000, we retired $7,000,000 of 8.68 percent Series A Unsecured MTNs due February 7, 2022. We retired $10,000,000 of 8.80 percent Series A Unsecured MTNs at maturity on February 22, 2000.

All of the above debt retirements, including transaction costs, were made from the proceeds received from the 1999 sale of our electric generating assets.

On November 8, 2000, Touch America entered into a $400,000,000 5-year Senior Secured Credit Facility for use in our telecommunications operations. The loan facility consists of a $200,000,000 term loan and $200,000,000 revolver, either of which we may use for short- or long-term borrowing. At December 31, 2000, $100,000,000 was outstanding under the term loan. Because the term loan must be prepaid under certain conditions, one of which is the sale of our remaining energy businesses, the amount has been classified as due within one year on the Consolidated Balance Sheet. The sale of Continental Energy on February 21, 2001, required us to pay down $27,600,000 on March 8, 2001. With this repayment, the term loan portion of the facility is permanently reduced from $200,000,000 to $172,400,000. Under this facility, interest is assessed against outstanding balances at a variable rate based on Touch America's credit rating and the London Interbank Offered Rate. At December 31, 2000, the rate was 9.5 percent. Annual commitment fees are based on the amount of loans outstanding, and at December 31, 2000, they were 1.0 percent on the unused revolver and 0.75 percent on the unused portion of the term loan.

The electric and natural gas legislation discussed in Note 5, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets," 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 relating 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 a special purpose entity (SPE), which is a wholly owned subsidiary, to issue the bonds. At December 31, 2000, approximately $58,412,000 was outstanding, of which approximately $4,162,000 was classified as due within one year on the Consolidated 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 Consolidated 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. However, as a wholly owned subsidiary, the SPE's revenues and expenses are shown as revenues and expenses in the Consolidated 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.

Altana Exploration Ltd. (Altana), a wholly owned Canadian subsidiary, had an Extendible Revolving Term Credit Agreement with the Royal Bank of Canada. The maximum amount of credit available under this agreement was $28,000,000 in Canadian dollars. At December 31, 1999, the United States dollar amount outstanding under the agreement was $17,502,000 ($24,259,000 Canadian dollars). We sold our oil and natural gas businesses, including Altana, on October 31, 2000, and this loan was assumed by the purchaser.

As discussed in Note 13, “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 balance of $10,200,000 at December 31, 1999, in “Other” in the table above, and it is classified as due within one year on the Consolidated Balance Sheet. The final payment for $10,200,000 occurred on January 3, 2000.

Continental Energy, a wholly owned subsidiary, had a $10,725,000 note associated with construction of the Tenaska Frontier Partners, LTD Project plant in Grimes County, Texas. The note was retired in October 2000. This non-interest bearing note secured by Continental Energy’s guarantee to assure the availability of equity capital equal to Continental Energy’s investment is included in the 1999 “Other” amount in the table above, and it is classified as due within one year on the 1999 Consolidated Balance Sheet.

Scheduled debt repayments on the long-term debt outstanding at December 31, 2000, amount to: $169,054,000 in 2001; $7,244,000 in 2002; $23,575,000 in 2003; $8,651,000 in 2004; $4,744,000 in 2005; and $265,249,000 thereafter.

NOTE 11 - SHORT-TERM BORROWING

At December 31, 2000, we had committed lines of credit of $130,000,000 and uncommitted lines of $80,000,000. Facility or commitment fees on the committed lines of credit are not significant. We have the ability to issue up to $85,000,000 of commercial paper based on the total amount of unused committed lines of credit and revolving credit agreements.

At December 31, 2000, we had outstanding notes payable to banks for $75,000,000 at an average annual interest rate of 8.05 percent. Of these outstanding notes, $25,000,000 was issued from our committed lines of credit and the other $50,000,000 from our uncommitted lines of credit. In 2000, we replaced a $200,000,000 90-Day Credit Agreement with a $400,000,000 5-year Senior Secured Credit Facility, with Touch America as the borrower, for use in our telecommunications operations. For more information about this facility, see Note 10, “Long-Term Debt.”

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 benefit plans’ 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.

As a result of the sale of our electric generating assets in December 1999, 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 in December 1999. Pursuant to the sales agreement, when the calculation was finalized in February 2000, approximately $3,200,000 of additional assets were transferred to the purchaser’s trust. In accordance with SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans," we calculated a curtailment gain of approximately $4,100,000 and a settlement gain of approximately $7,800,000 in 1999. Due to regulatory accounting requirements, the gains were recorded as regulatory liabilities or offsets to regulatory assets, resulting in no income statement effect.

We offered a Special Retirement Program (SRP) to certain eligible employees during 2000. The SFAS No. 88 special termination charge resulting from 213 participants electing the SRP amounted to approximately $10,500,000. Of that amount, $661,000 was recorded as additional expense. Due to regulatory accounting requirements, the remaining amount was offset against regulatory liabilities, resulting in no income statement effect.

Effective October 31, 2000, we sold our oil and natural gas operations to PanCanadian. In conjunction with the sale, 90 participants were curtailed from the retirement plan and approximately $2,400,000 in assets were used to purchase annuities for benefits accrued through October 31, 2000. In accordance with SFAS No. 88, we calculated a curtailment gain of approximately $108,000 and a settlement gain of approximately $526,000.

Together with the majority of our subsidiaries, we also provide certain health care and life insurance benefits for eligible retired employees. 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 401(k) Retirement Savings Plan in conjunction with our retirement plans. We make matching contributions, including 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 obligation, and fair value of assets over the two-year period ending December 31, 2000, and a statement of the funded status as of December 31 of both years:

	Pension Benefits		**Other Benefits**	
	2000	**1999**	**2000**	**1999**
	(Thousands of Dollars)			
Change in benefit obligation:				
Benefit obligation at January 1 .	$ 242,005	$ 273,401	$ 21,628	$ 24,512
Service cost on benefits earned .	5,820	8,724	571	844
Interest cost on projected benefit obligation............	18,292	19,529	1,741	1,776
Plan amendments	7,578	8,578	-	-
Actuarial (gain)/loss	588	(32,712)	4,773	(502)
Acquisitions/divestitures	-	-	(337)	-
Curtailments	(462)	(5,712)	-	(3,093)
Settlements	(2,429)	(18,096)	-	-
Special termination benefits	10,476	-	-	-
Adjustments for liability transfers.....................	(1,999)	-	-	-
Gross benefits paid	(12,153)	(11,707)	(2,775)	(1,909)
Benefit obligation at December 31...................	$ 267,716	$ 242,005	$ 25,601	$ 21,628
Change in plan assets:				
Fair value of plan assets at January 1.....................	$ 276,248	$ 289,881	$ 9,916	$ 8,782
Actual return/(loss) on plan assets.......................	(5,683)	18,620	329	226
Employer contributions	-	-	2,237	2,817
Acquisitions/divestitures	(5,629)	(22,707)	-	-
Adjustments for asset transfers .	(2,682)	-	-	-
Gross benefits paid	(9,942)	(9,546)	(2,775)	(1,909)
Fair value of plan assets at December 31...................	$ 252,312	$ 276,248	$ 9,707	$ 9,916
Reconciliation of funded status:				
Funded status at end of year	$ (15,405)	$ 34,262	$ (15,895)	$ (11,712)
Unrecognized net:				
Actuarial gain.................	(28,394)	(65,893)	(1,129)	(6,263)
Prior service cost............	23,310	17,856	1,593	1,822
Transition obligation.........	121	(363)	10,554	11,751
Net amount recognized at December 31.................	$ (20,368)	$ (14,138)	$ (4,877)	$ (4,402)

The following table provides the amounts recognized in the Consolidated Balance Sheet as of December 31:

	Pension Benefits		**Other Benefits**	
	2000	**1999**	**2000**	**1999**
	(Thousands of Dollars)			
Prepaid benefit cost..............	$ 942	$ 7,571	$ -	$ -
Accrued benefit cost..............	(21,310)	(21,709)	(4,877)	(4,402)
Net amount recognized at December 31	$ (20,368)	$ (14,138)	$ (4,877)	$ (4,402)

The following tables provide the components of net periodic benefit cost for the pension and other postretirement benefit plans, portions of which have been deferred or capitalized, for fiscal years 2000, 1999, and 1998:

	Pension Benefits		
	2000	1999	1998
	(Thousands of Dollars)		
Service cost on benefits earned	$ 5,820	$ 8,719	$ 8,079
Interest cost on projected benefit obligation	18,291	19,540	18,238
Expected return on plan assets	(23,894)	(25,650)	(22,870)
Amortization of:			
Transition obligation	44	43	358
Prior service cost	1,826	1,741	1,468
Actuarial gain	(3,166)	(1,658)	(1,062)
Immediate recognition of DC conversion	-	-	(142)
Net periodic benefit cost (credit)	(1,079)	2,735	4,069
Special termination benefit charge	10,476	-	-
Curtailment (gain)/loss	(108)	(3,751)	3,964
Settlement gain	(526)	(7,844)	-
Net periodic benefit cost (credit) after curtailments and settlements	$ 8,763	$ (8,860)	$ 8,033

	Other Benefits		
	2000	1999	1998
	(Thousands of Dollars)		
Service cost on benefits earned	$ 571	$ 844	$ 777
Interest cost on projected benefit obligation	1,741	1,776	1,665
Expected return on plan assets	(818)	(722)	(671)
Amortization of:			
Transition obligation	897	1,098	1,120
Prior service cost	166	177	69
Actuarial gain	(186)	(133)	(274)
Net periodic benefit cost	2,371	3,040	2,686
Curtailment gain	-	(374)	-
Net periodic benefit cost after curtailments and settlements	$ 2,371	$ 2,666	$ 2,686

In 2000, funding for pension costs exceeded SFAS No. 87, "Employers' Accounting for Pensions," pension expense by $3,078,000. In 1999 and 1998, pension costs exceeded SFAS No. 87 pension expense by $1,631,000 and $1,780,000, respectively. 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. At December 31, 2000, the regulatory liability was $10,614,000.

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

	Pension Benefits		Other Benefits	
	2000	1999	2000	1999
	(Thousands of Dollars)			
Weighted average assumptions as of December 31:				
Discount rate	7.50%	7.75%	7.50%	7.75%
Expected return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	4.40%	4.40%	4.40%	4.40%

Assumed health care costs trend rates have a significant effect on the amounts reported for the health care plans. A 1 percent change 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 postretirement health care benefit cost	$ 99	$ (82)
Effect on the health care component of the accumulated postretirement benefit obligation	646	(541)

The assumed 2001 health care cost trend rates used to measure the expected cost of benefits covered by the plans is 9.00 percent. The trend rate decreases through 2007 to 5.50 percent.

NOTE 13 - CONTINGENCIES

❑ KERR PROJECT

A FERC order that preceded our sale of the Kerr Project 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, the purchaser of our electric generating assets 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 this and another of FERC's orders and the United States Department of Interior's conditions contained in them. In December 2000, FERC issued an order approving a settlement among the parties. On February 15, 2001, the Circuit Court dismissed the petitions for review. Consequently, the approximately $24,000,000 that we paid into escrow in 2000 will be released to the Confederated Salish and Kootenai Tribes (Tribes) to be used in accordance with the terms of the settlement and, when we subsequently transfer to the Tribes 669 acres of land on the Flathead Indian Reservation, we will have fulfilled our obligations under the terms of this settlement. Because PPL Montana assumed the obligation in excess of $24,000,000, the basis in the properties sold decreased and the regulatory liability associated with the deferred gain on the sale increased accordingly.

❑ LONG-TERM POWER SUPPLY AGREEMENTS

Long-term power supply agreements, primarily an agreement with a large industrial customer, have exposed us to losses and potential future losses. That agreement obligates us to deliver to our customer one half of its electric energy at a fixed price and the remainder at an index-based price with a cap. When the agreement expires at the end of 2002, the customer has an option to extend the agreement through 2004. If the customer exercises this option, however, only index-based prices with no cap would apply during the extension period. Until the end of 2002, we must supply this and other industrial customers with electric energy purchased through an agreement indexed to the Mid-Columbia (Mid-C) market. As a result, we are exposed to the risk that electric energy we purchase at Mid-C prices can be higher than the fixed sales rates at which we are required to sell electric energy pursuant to our power supply agreements.

In June 1998, we entered into a swap with the industrial customer whose agreement exposes us to most of our risk, so that the customer could effectively purchase all of its electric energy from us at a fixed rate. At the same time, we entered into a separate fixed-price purchase and related Mid-C index sale of equivalent volumes with other counterparties to hedge that swap and eliminate our exposure to fluctuating market prices. Both the purchase and sale agreements with the other counterparties remain effective through May 2001. During the third quarter 2000, however, our industrial customer whose contract exposes us to most of the commodity price risk increased its electric energy consumption, and wholesale electric prices increased substantially. The swap and related physical offset did not extend to the increase in our customer's consumption.

Specifically, the average monthly purchases of electric energy by this industrial customer increased more than 30 percent during the third quarter 2000 compared to the second quarter 2000. Average monthly wholesale electric prices in the Pacific Northwest, based on the Mid-C price index, more than doubled during the third quarter 2000 compared to the second quarter 2000. Because of these two events, the expenses of supplying our industrial customers with electric energy during the third quarter 2000 exceeded the associated revenues earned from these customers and the swap and physical offset by approximately $8,400,000. By contrast, for the entire six months ended June 30, 2000, the expenses incurred to supply these customers exceeded the associated revenues earned from these customers and the swap and physical offset by approximately $2,000,000.

To mitigate future losses, we entered into a five-month agreement in October 2000 with a counterparty – a fixed-for-floating financial swap whereby we fixed our purchase price on a portion of the electric energy needed to supply our industrial customers in exchange for a Mid-C index-based price. As long as our industrial customers do not materially change their estimated electric usage, this swap allows us to fix the total cost of supplying their electric energy during the term of the swap and, therefore, in conjunction with our existing agreements, should limit our losses from supplying these customers.

Based on the effects of the existing purchase and sales agreements, the financial swaps and customer usage, we incurred losses of approximately $6,000,000 in the fourth quarter 2000 and, assuming customer usage stays relatively constant, we expect to experience losses of approximately $4,000,000 in the first quarter 2001. If we continue to purchase electric energy at index-based market rates, or do not have other effective swaps in place, we estimate that the losses on agreements with these industrial customers – based on customer usage estimates and on forward price projections and broker quotations as of December 29, 2000 – could aggregate approximately $25,000,000 in the second quarter 2001 and more in subsequent quarters. Because of the volatility of the electric energy market in the western United States, particularly in the Pacific Northwest, and future possibilities of supplying these customers from alternative sources, we believe that estimating losses that we may experience beyond the second quarter 2001 would not be meaningful.

We will continue to recognize losses on these agreements if and as they occur. We continue to seek other opportunities to mitigate the commodity price risk associated with our power supply agreements, although we cannot assure that these efforts ultimately will be successful.

❑ **MISCELLANEOUS**

We and our subsidiaries are parties 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 14 - COMMITMENTS

❑ PURCHASE COMMITMENTS

Electric Utility

The Public Utilities Regulatory Policies Act (PURPA) requires a public utility to purchase power from 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, and operating and efficiency criteria specified by PURPA. The electric utility has 15 long-term QF contracts with expiration terms ranging from 2003 through 2032 that require us to make payments for energy capacity and energy received at prices established by the PSC. Three contracts account for 96 percent of the 101 MWs of capacity provided by these facilities. Montana's 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 5, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

The Asset Purchase Agreement with PPL Montana, dated as of October 31, 1998 and amended June 29, 1999 and October 29, 1999, 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 have not 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. Under both agreements, the annual cap is $22.25/MWh, which has been in effect for most of 2000 because wholesale electric energy prices in the Pacific Northwest have been higher than this amount. Assuming an 8.05 percent discount rate (our average short-term borrowing rate at December 31, 2000), current market indices, and current load forecasts, we estimate the net present value of the power purchased under the WTSAs at $81,000,000 for 2001 and $34,000,000 for 2002.

Our former affiliate, The Montana Power Trading & Marketing Company (MPT&M) – which we sold on October 31, 2000 as part of the oil and natural gas businesses – had entered into several power purchase agreements in 1998. These agreements were assigned to the electric utility in 2000. One agreement obligates us to purchase 40 MWs per hour at a fixed rate until May 2001, and the other to purchase 100 MWs per hour of firm capacity and firm energy at 100 percent load factor at a market-indexed rate until August 2001.

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 of these contracts, with expirations between 2002 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. Since 1998, the natural gas utility enters only 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 Act.

Exited Nonutility Operations

In our nonutility operations, we entered into various contracts that committed us to purchase electric energy and pipeline reserve capacity for natural gas shipments. We assigned the electric energy contracts to our utility operations in 2000, and we sold our former oil and natural gas operations on October 31, 2000.

Contractual Payments and Present Value

Total payments under all of these contracts for the prior three years were as follows:

	Utility		Exited Nonutility		Total
	Electric	Natural Gas	Electric	Natural Gas	
	(Thousands of Dollars)				
2000	$272,075	$ 7,101	$ -	$ 8,100	$287,276
1999	61,274	4,069	26,076	7,898	99,317
1998	50,611	3,508	15,355	4,454	73,928

Under the above agreements, the present value of future minimum payments, at a discount rate of 8.05 percent, is as follows:

	Utility		Total
	Electric	Natural Gas	
	(Thousands of Dollars)		
2001	$224,435	$ 5,003	$229,438
2002	42,905	4,450	47,355
2003	8,380	641	9,021
2004	8,001	546	8,547
2005	7,537	465	8,002
Remainder	97,486	395	97,881
	$388,744	$ 11,500	$400,244

Discontinued Coal Operations

Northwestern Resources entered into a lignite lease agreement that requires minimum annual payments of $1,125,000, adjusted quarterly for inflation, for overriding royalties. The payments, which began in 1991, will continue until Northwestern Resources pays the equivalent of $18,750,000, in 1986 dollars. At December 31, 2000, the remaining payments under this agreement were $7,411,000. Under current mine plans, Northwestern Resources expects to recoup these payments through lignite sales.

- **Telecommunications Commitments**

Construction Projects

Touch America has contracted with Northern Telecom, Inc. (Nortel) to furnish and install optical electronic equipment on certain fiber optic networks. In 2000, Touch America paid approximately $26,400,000 for these installations and will schedule others in 2001 as segments of fiber optic networks under construction are completed. Touch America also entered into an arrangement with Nortel for an estimated $70,000,000 of installations of Nortel's optical electronic equipment related to Touch America's June 30, 2000 acquisition of telecommunications properties, discussed in Note 4, "Acquisition of Telecommunications Properties." As of December 31, 2000, Touch America had invested approximately $48,900,000 of the estimated $70,000,000 installation cost.

In October 1999, Touch America entered into a contract to construct a high-speed, fiber optic network for AT&T Corp (AT&T). The contract allows Touch America to install its own fiber optic network at the same time and along the same routes it is constructing for AT&T. The network will span more than 4,300 miles and will cover six different routes in the West, Pacific

Northwest, Northern Rocky Mountains, and Midwest. The contract contains capped performance incentives if we meet, and capped penalties if we do not meet, aggressive completion targets. All routes are scheduled for completion in mid-2001. We estimate the cost of the project at $488,000,000, of which approximately $205,000,000 was invested in 2000 and $283,000,000 is budgeted for 2001. We expect AT&T and other third parties to reimburse us for approximately 50 percent of the total cost, as stages of the project are completed.

In July 2000, Touch America entered into two separate agreements involving a route from Minneapolis to Chicago. This route makes up 500 miles of the 4,300-mile build-out that Touch America is constructing in tandem with its construction of a fiber optic network for AT&T. One agreement with Adesta Communications, Inc. gives Touch America the exclusive and indefeasible right to use up to 6 ducts along routes totaling approximately 151 miles within metropolitan Chicago for 24 years, with an option to renew for an additional 20 years at then-existing market rates. Touch America agreed to pay $16,000,000 for these rights, of which $14,000,000 has been paid through December 2000. Annual maintenance fees are expected to be approximately $200,000.

The second agreement, with the Chicago Transit Authority, gives Touch America an exclusive and indefeasible right to use 6 ducts along an approximately 18-mile route for 22 years, with an option to renew upon the mutual agreement of the parties. Touch America will pay $9,000,000 for these rights, of which $8,200,000 has been paid through December 2000. Annual maintenance fees are expected to be approximately $45,000.

In December 2000, Touch America contracted with Cisco Systems, Inc. (Cisco) to install computer equipment at 7 Points of Presence (POPs) on Touch America's fiber optic networks in the western United States. This equipment will allow Touch America to sell Internet Protocol (IP) at those sites. Touch America expects the installations to be completed in the second quarter 2001 and will pay Cisco $6,400,000 upon completion.

Joint Ventures

Touch America has entered into strategic alliances to expand its network and increase its revenues. In accordance with the agreements governing these relationships, Touch America is committed to contribute capital at various times.

In May 2000, Touch America and Sierra Pacific Communications, a subsidiary of Sierra Pacific Resources, formed a 50-50 joint venture, named Sierra Touch America, LLC, to construct a fiber optic network between Sacramento and Salt Lake City. This network will make up 750 miles of the 4,300-mile build-out that Touch America is constructing in tandem with its construction of a fiber optic network for AT&T. Sierra Touch America, LLC has begun construction of this route and expects to complete the route in mid-2001 at an estimated cost of $100,000,000. Touch America will purchase 4 of the 6 conduits of the network and sell 3 to AT&T and exchange another with a third party. Sierra Touch America, LLC will retain ownership of the remaining 2 conduits, of which each partner will have an equal share. At year-end 2000, Touch America and Sierra Pacific Communications each contributed $2,675,000 to the joint venture, and Touch America paid $10,000,000 toward the purchase of the 4 conduits. The terms of the joint venture agreement give Sierra Touch America, LLC a partial interest in the metropolitan fiber networks that Sierra Pacific Communications operates in Reno and Las Vegas.

In January 2000, Touch America and AEP Communications LLC, a subsidiary of American Electric Power, formed a 50-50 joint venture named American Fiber Touch, LLC (AFT) to connect national and regional fiber optic networks between Plano, Illinois and St. Louis, Missouri. This network will make up 296 miles of the 4,300-mile fiber optic network discussed above. American Fiber Touch has begun construction of the Plano-St. Louis route and expects to complete it in the second quarter 2001 at an estimated cost of $43,000,000. At year-end 2000, Touch America had advanced $6,950,000 for construction costs, and it plans to contribute $14,600,000 in 2001.

In August 1999, Touch America and Xcel (formerly known as New Century Energies or NCE) formed a 50-50 joint venture called Northern Colorado Telecommunications, LLC to provide a full range of telecommunication services, including private line service, to enterprises in the Denver metropolitan area. For the venture, Xcel contributed long-term indefeasible rights of use of its existing fiber optic network in the Denver metropolitan area; Touch America will construct six miles of fiber optic cable and install optical electronic equipment at an estimated cost of $10,000,000. Since the project's inception, Touch America has contributed $3,800,000 and plans to contribute $4,500,000 in 2001 and $500,000 in both 2002 and 2003.

In August 1999, Touch America and Qwest Wireless (formerly known as U S WEST Wireless) entered into a 49.9-50.1 joint venture, TW Wireless (TWW), to provide "one number" wireless telephone service in an eight-state region of the Pacific Northwest and Upper Midwest. That service provides a customer with one directory number for cell phone and home or business phone. Both companies contributed PCS licenses to the venture. To date, Touch America has contributed approximately $20,700,000 toward the costs of the wireless infrastructure and will contribute an estimated total of $35,800,000 more in 2001 and 2002.

In November 1999, FTV Communications LLC (FTV), the limited liability company formed by Touch America, Williams Communications, and Enron Broadband Services, began an expansion of regeneration sites along the Portland to Las Vegas portion of the fiber optic route that FTV constructed. FTV expects to complete the project in the second quarter 2001, and Touch America's share of the costs is approximately $3,800,000.

In June 1999, Touch America and Iowa Network Services, Inc. (INS) formed Iowa Telecommunications Services, Inc. (ITS) to purchase from a third party domestic access lines connected to telephone exchanges in Iowa. However, because the organizational and capital structure of ITS did not fit Touch America's growth strategy, Touch America sold its equity position in ITS in April 2000, with no gain or loss recorded. Under the terms of the exit agreement:

- Touch America sold its 31 percent interest in ITS to INS, and INS released Touch America from its share of the ITS obligations;
- Upon the closing of the third-party purchase transaction, which occurred on June 30, 2000, INS reimbursed Touch America approximately $7,600,000 for Touch America's cash outlays to ITS, with interest on the funds extended; and
- Touch America withdrew its $14,000,000 letter of credit from ITS upon the closing of the third-party purchase transaction.

Exchanges

In March 2000, Touch America and Williams Communications, Inc. agreed to an exchange of fiber and cash to expand both companies' fiber optic networks. Touch America received 24 fibers on a 1,053-mile route and $650,000 in exchange for 24 fibers on a 1,213-mile route. This exchange will expand Touch America's network from Denver to Kansas City, Missouri to Des Moines to Minneapolis.

Investment

In January 2000, Touch America signed a purchase agreement with Minnesota PCS, LP (MPCS) to acquire a 25 percent interest in MPCS' wireless telephone business, which owns PCS licenses in North Dakota, South Dakota, Minnesota, and Wisconsin. In accordance with the agreement, Touch America made an initial equity investment of $2,700,000 in MPCS and in August 2000 loaned MPCS $12,000,000 in interest-bearing notes payable on October 1, 2002. From October through December 2000, Touch America loaned an additional $4,375,000 to MPCS to cover network construction and operating costs. Touch America also has guaranteed the payment of $7,420,000 in loans made to MPCS through 2007.

Leases

In January 2000, Touch America entered into a Reciprocal IRU Lease and Exchange Option Agreement with Velocita (formerly known as PF.Net Construction Corp). This agreement is a 20-year IRU lease with an option to exchange the leased property at a future date. Under the agreement, Touch America will lease approximately 5,900 route miles from Velocita and Velocita will lease approximately 4,400 miles of fiber from Touch America. Prior to commencement of the lease, Touch America will prepay $48,500,000 for the difference in route miles. The prepayment will be amortized to expense over the 20-year lease term. As of December 31, 2000, approximately $12,000,000 had been paid.

Based on all of the Touch America agreements above, the present value of Touch America's estimated payments discounted at a rate of 8.05 percent is as follows:

2001	2002	2003	Total
	(Thousands of Dollars)		
$353,900	$ 5,400	$ 900	$360,200

Touch America has also entered into operating lease agreements for private line, long-distance, local-access, and equipment services, as well as office space, with varying termination dates, for which it paid approximately $2,400,000 in 2000 and expects to pay approximately $4,000,000 in 2001.

- **LEASE COMMITMENTS**

On December 30, 1985, we sold our 30-percent share of Colstrip Unit 4 and agreed to lease back our share under a net, 25-year lease with annual payments of approximately $32,000,000. We have been accounting for this transaction as an operating lease. We did not sell this nonutility leasehold interest and its related assets and liabilities and contract obligations to PPL Montana in 1999. This lease is included in the anticipated sale of the utility business to NorthWestern Corporation. We have no other material minimum operating lease payments.

Capitalized leases are not material and are included in other long-term debt.

Rental expense for the prior three years, including Colstrip Unit 4 and Touch America, was $44,300,000 for 2000, $59,300,000 for 1999, and $58,800,000 for 1998.

NOTE 15 – INFORMATION ON INDUSTRY SEGMENTS

Our continuing telecommunications business owns, operates, and develops a fiber optic network and provides wireless services mainly through PCS and LMDS. Our telecommunication business offers a full line of high-speed voice, data, video, and Internet services; provides colocation services; leases dark fiber and conduit rights on the network; and offers construction management oversight services for installation of fiber networks. Our continuing utility business purchases, transmits, and distributes electric energy and natural gas, and the Colstrip Unit 4 division manages long-term power supply agreements. Continental Energy developed and invested in independent power projects and other energy-related businesses. We closed the sale of Continental Energy on February 21, 2001.

In our discontinued coal operations, we mine and sell coal and lignite; in our former oil and natural gas operations, we explored for, developed, produced, processed, and sold crude oil and natural gas and traded crude oil, natural gas, and natural gas liquids. We closed the sale of our former oil and natural gas operations on October 31, 2000.

Identifiable assets of each industry segment are principally those assets used in our operation of those industry segments. Corporate assets are principally cash and cash equivalents, temporary investments, and administrative services' properties.

We consider segment information for foreign operations insignificant.

The following tables present selected information on our industry segments' continuing operations:

NOTE 15 - INFORMATION ON INDUSTRY SEGMENTS

Year Ended December 31, 2000
(Thousands of Dollars)

CONTINUING

	Tele-communications	Electric	Natural Gas
Sales to unaffiliated customers	$ 322,952	$ 535,390	$ 129,373
Intersegment sales	334	1,036	269
Depreciation, depletion, and amortization	22,423	39,559	8,830
Pretax operating income	49,670	18,167	28,113
Interest expense	812	30,289	16,077
Interest income	1,109	16,614	4,869
Earnings from unconsolidated investments	(1,473)	-	-
Income tax expense	18,881	(2,091)	2,861
Capital expenditures	554,119[a]	42,718	7,546
Identifiable assets	1,085,324[b]	1,144,684	261,768

CONTINUING (continued)

	Continental Energy	Other	Corporate
Sales to unaffiliated customers	$ 1,000	$ 10,993	$ -
Intersegment sales	-	1,536	-
Depreciation, depletion, and amortization	480	5,734	-
Pretax operating loss	(1,852)	(16,492)	-
Interest expense	31	3,999	-
Interest income	3,328	3,992	-
Earnings from unconsolidated investments	55,627	-	-
Income tax expense	20,318	(6,371)	-
Capital expenditures	12,230	11,600	16,003
Identifiable assets	37,091	16,755	177,524

RECONCILIATION TO CONSOLIDATED

	Segment Total	Adjustments[c]	Consolidated Total
Sales to unaffiliated customers	$ 999,708	$ -	$ 999,708
Intersegment sales	3,175	(3,175)	-
Depreciation, depletion, and amortization	77,026	-	77,026
Pretax operating income	77,606	-	77,606
Interest expense	51,208	(11,308)	39,900
Interest income	29,912	(11,308)	18,604
Earnings from unconsolidated investments	54,154	-	54,154
Income tax expense	33,598	-	33,598
Capital expenditures	644,216	-	644,216
Identifiable assets	2,723,146	282,129[d]	3,005,275

[a] This amount includes approximately $205,900,000 related to our June 30, 2000 telecommunications acquisition.
[b] This amount includes approximately $145,600,000 of intangible assets related to our June 30, 2000 acquisition.
[c] The amounts indicated include certain eliminations between the business segments.
[d] The adjustment of identifiable assets represents the identifiable assets of discontinued coal operations. The "Consolidated Total" of identifiable assets represents the consolidated total of both continuing and discontinued industry segments and, therefore, differs from the Consolidated Balance Sheet (which nets assets and liabilities of discontinued operations). The difference between the $2,816,794,000 figure shown on the Consolidated Balance Sheet and the $3,005,275,000 shown above is attributable to $188,481,000 of discontinued coal liabilities that were netted with assets in "Investment in discontinued coal operations" on the Consolidated Balance Sheet.

❑ INFORMATION ON INDUSTRY SEGMENTS (Continued)

Year Ended December 31, 1999
(Thousands of Dollars)

CONTINUING

	Tele-communications	Electric	Natural Gas
Sales to unaffiliated customers	$ 84,903	$ 531,883	$ 111,416
Intersegment sales	1,012	14,221	331
Depreciation, depletion, and amortization	9,048	56,282	9,279
Pretax operating income	25,801	113,740	16,459
Interest expense	1	38,467	15,229
Interest income	810	4,524	545
Earnings from unconsolidated investments	9,839	-	-
Income tax expense	14,088	13,054	391
Capital expenditures	153,617	50,503	13,115
Identifiable assets	290,722	1,089,017	406,413

CONTINUING (continued)

	Continental Energy	Other	Corporate
Sales to unaffiliated customers	$ 1,310	$ 47,660	$ -
Intersegment sales	-	1,665	-
Depreciation, depletion, and amortization	414	4,553	-
Pretax operating loss	(674)	(17,397)	-
Interest expense	18	3,357	-
Interest revenue	5,645	6,926	-
Earnings from unconsolidated investments	21,042	-	-
Income tax expense	8,136	(4,839)	-
Capital expenditures	-	-	15,957
Identifiable assets	24,114	14,008	630,417

RECONCILIATION TO CONSOLIDATED

	Segment Total	Adjustments[a]	Consolidated Total
Sales to unaffiliated customers	$ 777,172	$ -	$ 777,172
Intersegment sales	17,229	(17,229)	-
Depreciation, depletion, and amortization	79,576	-	79,576
Pretax operating income	137,929	-	137,929
Interest expense	57,072	(9,987)	47,085
Interest income	18,450	(9,987)	8,463
Earnings from unconsolidated investments	30,881	-	30,881
Income tax expense	30,830	-	30,830
Capital expenditures	233,192	-	233,192
Identifiable assets	2,454,691	594,052[b]	3,048,743

[a] The amounts indicated include certain eliminations between the business segments.
[b] The adjustment of identifiable assets represents the identifiable assets of operations that became discontinued in 2000 – the consolidated coal and oil and natural gas operations.

❑ INFORMATION ON INDUSTRY SEGMENTS (Continued)

Year Ended December 31, 1998
(Thousands of Dollars)

CONTINUING

	Telecommunications	Electric	Natural Gas
Sales to unaffiliated customers	$ 87,792	$ 526,527	$ 107,354
Intersegment sales	1,298	4,722	425
Depreciation, depletion, and amortization	7,090	59,213	8,705
Pretax operating income	39,095	127,709	15,019
Interest expense	1	48,903	12,946
Interest income	668	4,523	925
Earnings from unconsolidated investments	10,865	-	-
Income tax expense	19,772	27,760	168
Capital expenditures	56,203	61,938	21,989
Identifiable assets	189,561	1,664,775	405,670

CONTINUING (continued)

	Continental Energy	Other	Corporate
Sales to unaffiliated customers	$ 1,296	$ 47,988	$ -
Intersegment sales	-	1,913	-
Depreciation, depletion, and amortization	6,316	3,921	-
Pretax operating loss	(7,674)	(20,164)	-
Interest expense	58	9,716	-
Interest income	3,838	944	-
Earnings from unconsolidated investments	89,525	-	-
Income tax expense	30,946	(11,803)	-
Capital expenditures	10,725	-	189
Identifiable assets	33,483	14,213	43,211

RECONCILIATION TO CONSOLIDATED

	Segment Total	Adjustments[a]	Consolidated Total
Sales to unaffiliated customers	$ 770,957	$ -	$ 770,957
Intersegment sales	8,358	(8,358)	-
Depreciation, depletion, and amortization	85,245	-	85,245
Pretax operating income	153,985	-	153,985
Interest expense	71,624	(6,759)	64,865
Interest income	10,898	(6,759)	4,139
Earnings from unconsolidated investments	100,390	-	100,390
Income tax expense	66,843	-	66,843
Capital expenditures	151,044	-	151,044
Identifiable assets	2,350,913	577,182[b]	2,928,095

[a] The amounts indicated include certain eliminations between the business segments.
[b] The adjustment of identifiable assets represents the identifiable assets of operations that became discontinued in 2000 – the consolidated coal and oil and natural gas operations.

NOTE 16 – NEW ACCOUNTING PRONOUNCEMENTS

❑ Staff Accounting Bulletin No. 101

SAB No. 101, "Revenue Recognition in Financial Statements" was issued by the SEC in December 1999 and is applicable to us beginning in the fourth quarter 2000.

As it relates to our companies, SAB No. 101 mainly affects Touch America. It requires that particular one-time charges received from customers be recognized as revenues over the period of time that the charges are earned rather than as revenues when assessed or paid. Our telecommunications operations realize payment of one-time fees for such items as installations and activations. Prior to SAB No. 101, we recognized these revenues when received. With the adoption of SAB No. 101 in the fourth quarter 2000, we now recognize these revenues over the period in which they are earned, which coincides with the number of years that those customers are anticipated to be customers of Touch America. The one-time charges all are received either from wholesale or commercial customers and, due to the number of transactions, the amounts cannot be segregated into the two customer classes. Under our policy, therefore, we amortize these deferred revenues over the average lives of wholesale and commercial customers. We have not deferred any costs for installations, activations, or subscriber acquisitions.

We have evaluated SAB No. 101, and the cumulative catch-up for its adoption had no material effect on our consolidated financial position, results of operations, or cash flows. The adoption of SAB No. 101 affected only our 2000 operations.

❑ SFAS Nos. 133, 137, and 138

In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," which amends some accounting and reporting standards of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 was issued in June 1998. In July 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities: Deferral of the Effective Date of FASB Statement No. 133." SFAS No. 137 delayed for one year the effective date of SFAS No. 133, meaning that we are required to adopt SFAS No. 133 on January 1, 2001.

SFAS No. 133 expands the definition of a derivative and requires that all derivative instruments be recorded on an entity's balance sheet at fair value. As discussed in Note 2, "Decision to Sell Energy Businesses," we sold our oil and natural gas businesses - including MPT&M, which engaged in energy trading activities - on October 31, 2000.

We have reviewed our commodity purchase and sale agreements to evaluate exposure to potential embedded derivatives under SFAS No. 133 and SFAS No. 138. Effective January 1, 2001, we have accounted for the electric swap agreements described in Note 1, "Summary of Significant Accounting Policies," in the "Derivative Financial Instruments" section, as effective cash flow hedges pursuant to SFAS No. 133. Accordingly, these instruments have been marked to market, at January 1, 2001, with a corresponding credit entry made to Other Comprehensive Income for approximately $18,800,000 before income taxes, representing our cumulative transition adjustment in adopting SFAS No. 133.

NOTE 17 – SUBSEQUENT EVENT

In 2000, Touch America entered into a $400,000,000 5-year Senior Secured Credit Facility (Credit Facility) for use in our telecommunications operations. This Credit Facility consisted of a $200,000,000 term loan and $200,000,000 revolver, either of which we could use for short- or long-term borrowing. For further information regarding this facility, see Note 10, "Long-term Debt."

As a result of repayments totaling $91,900,000, the term loan portion of the facility is permanently reduced from $200,000,000 to $108,100,000. At September 30, 2001, borrowings under this Credit Facility aggregated $254,100,000. The Credit Facility provides that the proceeds from the pending sale of MPLLC to NorthWestern will pay down the entire balance of the Credit Facility. Thereafter, the Credit Facility may permit additional borrowings.

Based on financial performance for the twelve-month period ending September 30, 2001, Touch America is not in compliance with financial covenants under its Credit Facility requiring Touch America to maintain a ratio of total debt to EBITDA (earnings before interest, taxes, depreciation and amortization) of not more than 4.50:1 and a ratio of senior secured debt to EBITDA of not more than 3.50:1. On November 14, 2001, Touch America received a 30-day waiver of the requirement to comply with the financial covenants from the lending banks under the Credit Facility. The waiver is conditional upon Montana Power Company repaying to Entech, Inc., our wholly owned subsidiary and Touch America's parent company, by November 30, 2001, at least $25,000,000 of an intercompany loan. The proceeds will be used for general corporate purposes of Touch America. As a condition to the waiver, Touch America has agreed - among other things – to an increase in the pricing of the Credit Facility, including a 50 basis point increase in the commitment fee, and that Touch America may not make further borrowings under its revolving credit facility.

Touch America's Credit Facility is currently its principal source of funds to meet capital requirements. As a result of Touch America's failure to comply with the Credit Facility financial covenants discussed above, and based on the terms of the waiver entered into with the lending banks under the facility, Touch America may not make further borrowings under the Credit Facility at the present time. Touch America is seeking additional funds from the lending banks under the Credit Facility to meet its near term cash requirements but there can be no assurances that additional funds will be made available or if they are, that the timing of the availability will allow Touch America to meet its commitments. Touch America does not believe that it currently has access to the capital markets on reasonable terms to meet its capital requirements. If Touch America does not reach agreement with the lending banks under its Credit Facility or receive additional funds from other sources, Touch America will be unable to meet its obligations and could experience a material adverse impact on its financial condition and face challenges to its financial viability. The lending banks under the Credit Facility do not have recourse against the Company's assets not attributable to Touch America.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Deductions*	Balance at close of period
		(Thousands of Dollars)			
Year Ended:					
December 31, 2000					
Reserves deducted in balance sheet from assets to which they apply:					
Doubtful accounts					
Utility	$ 1,104	$ 151	$ -	$ 91	$ 1,164
Nonutility	1,001	9,355	3,219	3,283	10,292
Total	$ 2,105	$ 9,506	$ 3,219	$ 3,374	$ 11,456
December 31, 1999					
Reserves deducted in balance sheet from assets to which they apply:					
Doubtful accounts					
Utility	$ 1,044	$ 2,010	$ -	$ 1,950	$ 1,104
Nonutility	862	187	(10)	38	1,001
Total	$ 1,906	$ 2,197	$ (10)	$ 1,988	$ 2,105
December 31, 1998					
Reserves deducted in balance sheet from assets to which they apply:					
Doubtful accounts					
Utility	$ 984	$ 1,749	$ -	$ 1,689	$ 1,044
Nonutility	827	182	(11)	136	862
Total	$ 1,811	$ 1,931	$ (11)	$ 1,825	$ 1,906

* Deductions are of the nature for which the reserves were created. In the case of the reserve for doubtful accounts, deductions from this reserve are reduced by recoveries of amounts previously written off.

Exhibit 99b

AMENDED MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2000

RESULTS OF OPERATIONS

As a result of our restructuring efforts, we have evaluated our operations to determine which segments should be included in continuing or discontinued operations. Because the sale of our utility business remains subject to shareholder approval, we have included the results of operations, financial position, and cash flows of our electric (including Colstrip Unit 4) and natural gas utility business in continuing operations. We plan to schedule a special meeting of our shareholders in the second or third quarter 2001 to consider and vote on the sale and other matters.

We have not afforded Continental Energy discontinued operations accounting treatment since we have historically reported Colstrip Unit 4 with Continental Energy as the Independent Power Group segment. Although we sold Continental Energy on February 21, 2001, the sale of our utility business includes Colstrip Unit 4. Consequently, we have reflected Continental Energy activity in continuing operations for all periods presented.

As a result of our Board of Directors' approval to enter into definitive agreements with respect to our former oil and natural gas and our coal operations, we have applied discontinued operations accounting treatment to these operations, resulting in the following:

- We have separately reported net income after income taxes from oil and natural gas and coal operations in income from discontinued operations for all periods presented to reflect the reclassification of these operations as discontinued.

- On our Consolidated Balance Sheet at December 31, 2000, no balances exist with respect to our former oil and natural gas operations, which we sold on October 31, 2000, and we have netted assets and liabilities of our discontinued coal operations in "Current assets," under "Investment in discontinued operations."

- We have reported cash flows of oil and natural gas and coal operations as "Net cash provided by (used for) discontinued operations" – whether segregated by operating, investing, or financing activities.

Our planned restructuring is expected to transform our Company from a diversified electric and natural gas utility business to a national telecommunications transport services business. Because this restructuring remains subject to various approvals, we can provide no assurance that it will occur in the timeframe contemplated. For additional information on the status of the sales of our energy businesses and our application of discontinued operations accounting to our former oil and natural gas operations and coal operations, see Note 2, "Decision to Sell Energy Businesses."

❑ NET INCOME PER SHARE OF COMMON STOCK

Consolidated net income available for common stock was $195,801,000 in 2000, compared with $146,656,000 in 1999, and $161,930,000 in 1998.

The following table shows the sources of consolidated net income on a per-share (basic) basis for 2000, 1999, and 1998 and each source's percentage contribution to consolidated earnings per share.

	Year Ended December 31					
	2000[1]	Percent Contribution	1999	Percent Contribution	1998	Percent Contribution
Continuing Operations ..	$0.69	37%	$0.86	64%	$1.11	76%
Discontinued Operations	1.17	63%	0.48	36%	0.36	24%
Consolidated	$1.86	100%	$1.34	100%	$1.47	100%

[1]2000 figures for discontinued operations include gain on sale of discontinued oil and natural gas operations.

2000 COMPARED WITH 1999

- **CONSOLIDATED RESULTS**

Net income from continuing operations for 2000 decreased when compared with 1999. While our telecommunications and natural gas utility operations had improved operating results, and "Other income - net" increased as a result of gains recognized by Continental Energy from its unconsolidated investments, decreased income from electric utility operations more than offset these improvements.

We now classify all earnings from our unconsolidated investments in "Other income - net." We previously reported these earnings separately in revenues under "Earnings from unconsolidated investments" and have reclassified all amounts from prior periods to reflect this change.

Income from our telecommunications operations for 2000 nearly doubled when compared with 1999, increasing approximately 93 percent. Our June 30, 2000 acquisition contributed substantially to increased revenues.

For 2000, income from electric utility operations decreased approximately 84 percent when compared with 1999, primarily because of the effects of the December 1999 sale of our electric generating assets. Income from natural gas utility operations increased approximately 71 percent as compared to 1999, mainly due to an increase in rates and a weather-related increase in volumes sold.

Revenues and expenses in other operations decreased principally because these operations no longer reflect the electric trading and marketing activities of our former affiliate, The Montana Power Trading & Marketing Company (MPT&M), which was sold to PanCanadian.

Interest expense decreased mainly because of the net retirement of long-term debt in 1999 and early 2000, the effects of which were partially offset by a reversal of interest expense in the fourth quarter 1999 related to an environmental liability.

The increase of approximately $33,700,000 in "Other income - net" was principally due to Continental Energy's pretax gain recognized in the second quarter 2000 from the sale of its equity interest in the Brazos project in Cleburne, Texas, and increased interest income. "Other income - net" also includes approximately $1,500,000 of loss from unconsolidated telecommunications investments, as compared with approximately $9,800,000 of earnings for 1999. The decrease resulted primarily from anticipated losses from investments in two wireless joint ventures and a $6,000,000 decrease in dark-fiber transactions, mainly from the FTV Communications LLC (FTV) joint venture.

Income from discontinued operations increased compared with 1999 mainly because of the gain of approximately $62,000,000, net of income taxes and a regulatory liability of approximately $32,500,000, we recorded relating to the fourth quarter 2000 sale of our oil and natural gas operations.

CONTINUING OPERATIONS

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
TELECOMMUNICATIONS:			
REVENUES:			
Revenues	$ 322,952	$ 84,903	$ 87,792
Intersegment revenues	334	1,012	1,298
	323,286	85,915	89,090
EXPENSES:			
Operations and maintenance	179,648	34,824	27,110
Selling, general, and administrative	66,203	12,480	12,172
Taxes other than income taxes	5,342	3,762	3,623
Depreciation and amortization	22,423	9,048	7,090
	273,616	60,114	49,995
INCOME FROM TELECOMMUNICATIONS OPERATIONS	49,670	25,801	39,095
UTILITY AND COLSTRIP UNIT 4:			
ELECTRIC UTILITY AND COLSTRIP UNIT 4:			
REVENUES:			
Revenues	535,390	531,883	526,527
Intersegment revenues	1,036	14,221	4,722
	536,426	546,104	531,249
EXPENSES:			
Power supply	342,098	203,790	200,203
Transmission and distribution	38,330	49,355	40,182
Selling, general, and administrative	58,545	70,242	55,860
Taxes other than income taxes	39,727	52,695	48,082
Depreciation and amortization	39,559	56,282	59,213
	518,259	432,364	403,540
INCOME FROM ELECTRIC UTILITY AND COLSTRIP UNIT 4 OPERATIONS	18,167	113,740	127,709
NATURAL GAS UTILITY:			
REVENUES:			
Revenues (other than gas supply cost revenues)	91,457	78,657	75,414
Gas supply cost revenues	37,916	32,759	31,940
Intersegment revenues	269	331	425
	129,642	111,747	107,779
EXPENSES:			
Gas supply costs	37,916	32,759	31,940
Other production, gathering, and exploration	1,092	2,338	2,284
Transmission and distribution	15,093	14,635	15,556
Selling, general, and administrative	24,371	21,944	20,191
Taxes other than income taxes	14,227	14,333	14,084
Depreciation, depletion, and amortization	8,830	9,279	8,705
	101,529	95,288	92,760
INCOME FROM NATURAL GAS UTILITY OPERATIONS	28,113	16,459	15,019

CONTINUING OPERATIONS (Continued)

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
CONTINENTAL ENERGY:			
REVENUES:			
Revenues	1,000	1,310	1,296
EXPENSES:			
Operations and maintenance	10	258	750
Selling, general, and administrative	2,361	1,310	1,903
Taxes other than income taxes	1	2	1
Depreciation and amortization	480	414	6,316
	2,852	1,984	8,970
LOSS FROM CONTINENTAL ENERGY OPERATIONS	(1,852)	(674)	(7,674)
OTHER OPERATIONS:			
REVENUES:			
Revenues	10,993	47,660	47,988
Intersegment revenues	1,536	1,665	1,913
	12,529	49,325	49,901
EXPENSES:			
Operations and maintenance	1,700	50,140	51,634
Selling, general, and administrative	19,893	10,888	13,212
Taxes other than income taxes	1,694	1,141	1,298
Depreciation and amortization	5,734	4,553	3,921
	29,021	66,722	70,065
LOSS FROM OTHER OPERATIONS	(16,492)	(17,397)	(20,164)
INTEREST EXPENSE AND OTHER INCOME:			
Interest	34,408	41,593	59,373
Distributions on company obligated mandatorily redeemable preferred securities of subsidiary trust	5,492	5,492	5,492
Other income - net	(72,085)	(38,407)	(103,419)
	(32,185)	8,678	(38,554)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	109,791	129,251	192,539
INCOME TAXES	33,598	30,830	66,843
NET INCOME FROM CONTINUING OPERATIONS	76,193	98,421	125,696
DIVIDENDS ON PREFERRED STOCK	3,690	3,690	3,690
NET INCOME FROM CONTINUING OPERATIONS AVAILABLE FOR COMMON STOCK	$ 72,503	$ 94,731	$ 122,006

❑ TELECOMMUNICATIONS OPERATIONS

After completion of our proposed restructuring, we expect Touch America to be a stand-alone company focused on providing telecommunications services, primarily for wholesale and business customers. Because the restructuring of our Company is dependent on many variables, we cannot assure that we will be able to complete our restructuring or that, if our restructuring is completed, Touch America will be successful in meeting its goals. While the telecommunications business is constantly changing and increasingly competitive, we will strive to succeed as we focus on this business.

By the end of 2001, we expect to have approximately $1,600,000,000 in total assets, including approximately $350,000,000 in cash. We expect to have no debt and to generate approximately $670,000,000 in revenues during 2001 with an EBITDA margin modestly exceeding 20 percent, which was our margin during the last six months of 2000. Our calculation of EBITDA consists of earnings or loss before interest income and expense, income taxes, depreciation, and amortization. We calculate the EBITDA margin by dividing our EBITDA by revenues.

We continue to work toward a reduction of off-network carrier charges by integrating our operations and migrating customers onto our network. We also continue to seek to negotiate volume discounts with other carriers. If we succeed in these efforts, we would reduce our off-network costs which, in turn, would increase EBITDA and our EBITDA margin to a level in excess of the 20 percent mentioned above.

We expect to continue to add employees, particularly in the sales and sales-support areas. At the end of 1999, Touch America had approximately 185 employees. As a result of the June 30, 2000 telecommunications acquisition, we added nearly 200 employees, and at the end of 2000, we had increased our employee base to more than 600 employees. By the end of 2001, we expect to have approximately 1,200 employees.

Income from our telecommunications operations in 2000 nearly doubled when compared with 1999, increasing approximately $23,900,000, from $25,800,000 to $49,700,000. EBITDA in 2000 more than doubled when compared with 1999, increasing approximately $37,300,000, from $34,800,000 to $72,100,000. These significant increases resulted primarily from the June 30, 2000 acquisition from Qwest of wholesale, private line, long-distance, and other telecommunications customers in the former U S WEST fourteen-state region.

For information related to, among other matters, a waiver of the requirement to comply with certain financial covenants under Touch America's Credit Facility, as defined herein, see the "Liquidity and Capital Resources" section below.

Revenues

Revenues increased on Touch America's broadband network compared to 1999.

- Network services revenues, which include wholesale and dedicated business line revenues, increased approximately $176,400,000 to $219,600,000 as compared with $43,200,000 in 1999. Network services revenues, which comprise approximately 73 percent of our service revenues, increased primarily as a result of new customers acquired.

- Retail sales revenues, which include commercial and consumer long-distance revenues, increased approximately $57,800,000 to $82,500,000 as compared with $24,700,000 in 1999. Retail sales revenues comprise approximately 27 percent of our service revenues and also increased principally as a result of new customers acquired.

- Year-to-date increases in revenues of approximately $11,700,000 resulted mainly from equipment, engineering, and construction services provided by Touch America for infrastructure for a PCS joint venture in which Touch America has invested. Other equipment sales decreased approximately $5,300,000 due partly to increased 1999 activity related to the Y2K issue.

Prior to the June acquisition, our telecommunications business generated approximately 63 percent of its service revenues from network services revenues, principally on our fiber optic network. Prior to the acquisition, retail sales comprised approximately 37 percent of service revenues, which were also provided primarily on our fiber optic network. The acquisition increased our customer base and the geographic distribution of customers, and it also resulted in a significant increase in the percentage of revenues from network services (wholesale and dedicated business line services), the primary focus of the efforts of our expanding sales force. For more information on the June 30 acquisition, see Note 4, "Acquisition of Telecommunications Properties."

In 2000, we began classifying all earnings from our unconsolidated investments in "Other income - net" and have reclassified amounts from prior periods.

The following table shows year-to-year changes in commercial and consumer long-distance revenues for the previous two years.

	2000	**1999**
Revenues (Millions of Dollars) ...	$58	$4
Minutes sold	867%	31%
Price per minute	(59%)	(9%)
Customer growth	460%	26%

Expenses

Operations and maintenance (O&M) expenses increased approximately $144,800,000 due primarily to higher off-network charges for access to other telecommunications companies' systems to carry the increased traffic discussed above. Selling, general, and administrative (SG&A) expenses increased approximately $53,700,000 as a result of customer growth and the increased costs of expanding Touch America's infrastructure and our sales and marketing efforts. Our sales and sales-support staff increased from approximately 50 at the beginning of the year to approximately 300 by the end of the year. As productivity of this expanding new sales force increases, SG&A as a percentage of revenue is expected to decrease. Taxes other than income taxes increased approximately $1,600,000 and depreciation and amortization expense increased approximately $13,400,000, mainly due to continuing expansion of our fiber optic network and the additional assets acquired in 2000.

As previously discussed, prior to the acquisition, much of our telecommunications services were provided on our network. The increase in customer numbers and geographic distribution of customers has resulted in a significant percentage increase in our use of other telecommunications companies' fiber optic networks. These off-network charges currently represent the single largest operating expense for our telecommunications operations. As we continue to integrate the acquired operations into our Company and further expand our network, we will seek to reduce this dependence on other carriers and correspondingly reduce our off-network charges.

Regulatory

The Telecommunications Act of 1996 provides for significant deregulation of the United States telecommunications industry, including the local exchange and long-distance industries. This legislation remains subject to judicial review and additional Federal Communications Commission rulemaking and, therefore, we are unable to predict the ultimate effect of this regulation on our business.

Telecommunications services remain subject to regulation at the federal, state, local, and international levels. These regulations affect us and our existing and potential customers. Delays in receiving required regulatory approvals or in completing interconnection agreements with local exchange carriers may have a material adverse effect on us. In addition, many regulatory actions are underway or being contemplated by federal, state, local, and international authorities. These future legislative, judicial, and regulatory agency actions could increase our costs, causing the loss of customers and revenues, in addition to impeding or prohibiting our growth.

❑ UTILITY OPERATIONS

Weather

As measured by heating degree-days, temperatures in 2000 for our service territory were 10 percent colder than 1999 and level with the historic average. Temperatures in 1999 were 3 percent warmer than 1998 and 9 percent warmer than the historic average.

Accounting for the Effects of Regulation

We apply Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," to our regulated operations. Pursuant to this pronouncement, we recognize certain expenses and credits as they are reflected in revenues collected through rates established by cost-based regulation. 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.

We received proceeds in excess of book value for the sale of our generating assets and our previously regulated natural gas properties and are carrying the excess proceeds as a regulatory liability on the Consolidated Balance Sheet. For additional information on our Tier II filing, see Note 5, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

The Electric Act identifies regulatory assets and deferred charges that exist because of regulatory practices, as well as above-market costs associated with QF contracts, as recoverable transition costs. Based upon the anticipated recovery of these costs, we believe that discontinuing regulatory accounting treatment would not have a material adverse effect on our future consolidated financial position, results of operations, or cash flows. We expect our regulated transmission and distribution businesses will continue to have cost-based rates and, therefore, meet the criteria of SFAS No. 71.

In accordance with our October 31, 1998 Asset Purchase Agreement with PPL Montana, as amended June 29, 1999 and October 29, 1999, we expect to sell our portion of the 500-kilovolt transmission system associated with Colstrip Units 1, 2, and 3 to PPL Montana for $97,100,000. This transaction is expected to close in 2001. The after-tax proceeds that we expect to receive as a result of this transaction will remain with The Montana Power L.L.C., and we expect the gain resulting from the transaction to be addressed in the regulatory process.

After the completion of our proposed restructuring and sale of our electric and gas utility business to NorthWestern, Touch America shareholders will no longer be responsible for the obligations and liabilities of the utility operations. These liabilities and obligations will accompany the utility operations to NorthWestern.

Electric Utility (including Colstrip Unit 4)

Utility earnings are based on capital invested in utility plant. Because we no longer earn a return on approximately $497,000,000 of utility net plant as a result of the December 1999 sale of electric generating assets, we experienced an expected decline in utility earnings.

Prior to the sale, we billed revenues in part to cover the costs of operating the generating plants, pay taxes and interest, and to earn a return on our shareholders' investment. Since the sale, we continue to bill our core customers for energy supply, but now these revenues cover the costs to purchase power to serve these customers. These costs per MWh no longer fluctuate based on actual operating results, but are fixed based on an allocated cost-of-service price. Buyback contracts allow us to purchase power necessary to serve our core customers through the transition period ending on July 1, 2002. The price in the buyback contracts, which is annually capped at $22.25/MWh, represents our net fully allocated costs of service in current rates, replacing operations and maintenance expense, depreciation expense, property tax expense, and return on investment. We reflect the costs of purchased power under the buyback contracts in operating expenses as power supply expenses.

On December 21, 2000, the PSC extended our obligation to supply remaining customers from July 1, 2002 through June 30, 2004. We will act as an intermediary for our customers, purchasing energy in the market and supplying this energy to our customers. The possibility exists that, through legislative action, this obligation may be extended through June 30, 2007. We are working with the Montana Legislature and the PSC to fully recover the default supply costs.

On March 15, 2001, the PSC issued a Notice of Commission Action and Opportunity to Comment, stating the PSC's belief that it not only has continuing jurisdiction over our utility that provides fully regulated services to our customers, but also over the electric generating assets that we sold to PPL Montana in December 1999. In its Notice, the PSC stated that our closing of the sale of the electric generating assets to PPL Montana did not preclude the PSC from determining cost-based prices for customers during the extended transition period. In a work session on March 28, 2001, the PSC formally adopted its statement affirming its authority to make determinations regarding the generation assets during the extended transition period, while fostering the financial integrity of our utility.

In addition, the Montana Legislature is currently considering various energy-related proposals to maintain low energy prices. Several of these proposals address who should supply electric energy and what this energy should cost Montana consumers.

We cannot predict the ultimate outcome of these matters or their potential effect on our consolidated financial position, results of operations, or cash flows.

The following table categorizes revenues and volumes into "General Business Revenues," "Sales to Other Utilities," "Other," and "Intersegment." It also shows "Bundled Revenues" and "Distribution Only Revenues" separately for "General Business Revenues." While we no longer supply the electric energy for customers who have chosen other commodity suppliers, we continue to earn transmission and distribution revenues for moving their electric energy across our transmission and distribution lines. We reflect transmission revenues as "Other" revenues and distribution revenues as "Distribution Only Revenues."

	Revenues and Power Supply Expenses			Volumes		
	2000	**1999**	**%**	**2000**	**1999**	**%**
	(Thousands of Dollars)			(Thousands of MWh)		
REVENUES:						
General Business Bundled Revenues:						
Residential	$127,816	$127,572	-	1,979	1,810	9%
Small Commercial, Small Industrial, and Government and Municipal	143,512	159,872	(10%)	2,438	2,474	(1%)
Large Commercial, Large Industrial	41,979	37,707	11%	1,157	1,095	6%
Irrigation and Street Lighting	15,358	15,254	1%	156	144	8%
Total	328,665	340,405	(3%)	5,730	5,523	4%
General Business Distribution Only Revenues:						
Residential	577	-	-	7	-	-
Small Commercial, Small Industrial, and Government and Municipal	7,143	2,837	152%	346	128	170%
Large Commercial, Large Industrial	9,223	13,622	(32%)	1,727	1,614	7%
Total	16,943	16,459	3%	2,080	1,742	19%
Total General Business Revenues	345,608	356,864	(3%)	7,810	7,265	8%
Sales to Other Utilities	122,736	148,426	(17%)	2,172	5,023	(57%)
Other	67,046	27,752	142%	-	-	-
Intersegment	1,036	13,062	(92%)	-	66	-
Total	$536,426	$546,104	(2%)	9,982	12,354	(19%)
POWER SUPPLY EXPENSES:						
Hydroelectric	$ -	$ 21,576	-	-	3,692	-
Steam	-	54,969	-	-	4,685	-
Purchased Power and Other	342,098	127,245	169%	8,737	4,626	89%
Total	$342,098	$203,790	68%	8,737	13,003	(33%)

General Business Revenues

General Business Revenues decreased mainly because of a voluntary rate reduction filed with the PSC, effective February 2, 2000, and customers continuing to choose other suppliers. A weather-related increase in volumes sold partially offset this decrease. As discussed above, distribution revenues from customers who have chosen other suppliers are reflected as "General Business Revenues" while the associated transmission revenues are reflected as "Other" revenues in the table above.

Sales to Other Utilities

Sales to Other Utilities decreased mainly due to a decrease in sales of excess generation in the secondary markets related to the 1999 sale of our generating assets and the effects of an agreement with Colstrip Unit 4 and with the Los Angles Department of Water Power (LADWP). In December 1999, an agreement with the LADWP terminated the existing agreement (10 years remaining) and established a new agreement at a lower price. We received approximately $106,000,000 from the LADWP as a result of the termination of the existing agreement and the establishment of the new agreement. While the decrease in price under the new agreement effectively decreased our "Sales to Other Utilities" category, this decrease was offset in the "Other" revenues category from the recognition of revenues related to the prepayment over the remaining term of the agreement.

Other

Other revenues increased mainly because of increased revenues from the LADWP $106,000,000 prepayment discussed above, instruments relating to the long-term power supply agreements discussed in Note 13, "Contingencies," ancillary services revenues from our choice customers, and third-party transmission revenues from energy sales in the secondary market. Prior to the generation sale, our former affiliate, MPT&M, sold this energy in the secondary market, using our lines to transmit the energy across our service territory.

Intersegment

Intersegment revenues decreased principally because, as discussed above, MPT&M no longer sells energy in the secondary market.

Expenses

Power supply expenses for the electric utility increased mainly because of increased purchased power costs required to supply electric energy to our core customers, along with a higher average price for wholesale power under a purchase agreement that we use mainly to supply an industrial customer. A decrease in purchased power resulting from customers choosing other suppliers and from decreased fuel expenses because we no longer purchase fuel to operate the generating plants partially offset this increase.

Our agreements to supply electric energy to Duke Energy Trading & Marketing (DETM) and Puget Sound Energy (Puget) subject us to the possibility of unrecoverable losses because, to fulfill our supply obligations, we could have to purchase electric energy at market-based rates. In addition, our agreements to supply electric energy to several large industrial customers contain fixed-price terms and, therefore, subject us to the possibility of unrecoverable losses. For general information regarding the commodity price risk and potential adverse effects that we face as a result of our contractual commitments, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," in the "Other-Than-Trading Instruments" section, under "Commodity Price Exposure." For specific information regarding how the DETM and Puget agreements expose us to commodity price risk, see Item 7A, in the "Commodity Price Exposure" section, under "Colstrip Unit 4."

Long-term power supply agreements, primarily an agreement with a large industrial customer, expose us to commodity price risk. That agreement obligates us to deliver to our customer one half of its electric energy at a fixed price and the remainder at an index-based price with a cap. When the agreement expires at the end of 2002, the customer has an option to extend the agreement through 2004. If the customer exercises this option, however, only index-based prices with no cap would apply during the extension period. Until the end of 2002, we must supply this and other industrial customers with electric energy that we purchase through an agreement indexed to the Mid-Columbia (Mid-C) market. As a result, we are exposed to the risk that electric energy we purchase at Mid-C rates could be higher than the fixed sales rates that we receive pursuant to our power supply agreements.

For more specific information concerning the commodity price risk and potential adverse effects arising from our long-term power supply agreements, see Item 7A, in the "Commodity Price Exposure" section, under "Large Industrial Customers," and Note 13, "Contingencies," in the "Long-Term Power Supply Agreements" section.

Transmission and distribution expenses decreased primarily because, as discussed above, we are no longer selling surplus energy generated by us in the secondary markets. As a result, we did not incur the costs associated with using other utility companies' lines outside our service territory to transmit this energy.

SG&A expenses decreased approximately $11,700,000 mainly due to a decrease in regulatory amortizations related to the generation sale, decreased costs relating to the Enterprise Resource Planning (ERP) information system and the Enterprise Customer-Care (ECC) information system, decreased costs for public-purpose programs in accordance with the Universal System Benefits Charge (USBC) requirements of Montana's 1997 Electric Act, and decreased miscellaneous administrative items. We collect the costs associated with the public-purpose programs through a separate component of rates.

Taxes other than income taxes and depreciation expense decreased as a result of the sale of our electric generating assets.

Natural Gas Utility

The following table categorizes revenues and volumes related to our natural gas utility.

	Revenues			Volumes		
	2000	**1999**	**%**	**2000**	**1999**	**%**
	(Thousands of Dollars)			(Thousands of Dkt)		
REVENUES:						
Residential	$74,266	$63,921	16%	12,500	12,657	(1%)
Small Commercial, Small Industrial, and Government and Municipal	36,580	30,329	21%	6,192	5,874	5%
General Business Revenues	110,846	94,250	18%	18,692	18,531	1%
Less: Gas Supply Cost Revenues (GSC)	37,916	32,759	16%	-	-	-
General Business Revenues without GSC	72,930	61,491	19%	18,692	18,531	1%
Sales to Other Utilities	749	687	9%	223	229	(3%)
Transportation	16,918	15,197	11%	22,953	24,426	(6%)
Other	860	1,282	(33%)	-	-	-
Total	$91,457	$78,657	16%	41,868	43,186	(3%)

Revenues

All of our former Large Industrial and Large Commercial customers have now chosen other commodity suppliers. While we no longer supply the natural gas for those customers, we still earn transportation revenues from moving their natural gas through our pipelines.

"General Business Revenues," excluding gas-supply cost revenues, increased mainly because of a rate increase effective April 1, 2000 and an interim rate increase effective November 28, 2000. In addition, a weather-related increase in volumes sold and customer growth increased revenues. For additional information on our natural gas PSC filings, see Note 5, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

Expenses

Expenses, excluding gas-supply costs, increased chiefly because of regulatory amortizations and other miscellaneous administrative items.

- **CONTINENTAL ENERGY**

Continental Energy's income from operations decreased approximately $1,200,000 mainly due to increased SG&A expenses resulting chiefly from implementation of the ERP information system.

- **OTHER OPERATIONS**

Revenues and O&M expenses in other operations decreased primarily because these operations no longer reflect the electric trading activities of MPT&M. In addition, we purchased One Call Locators, Ltd. in January 2000 and its operating results are included in other operations. One Call's revenues and expenses partially offset the decreases mentioned above and are the primary cause for the increases in SG&A expenses and depreciation and amortization expense. We have reclassified into other operations all general corporate overhead expenses associated with, but not directly attributable to, the discontinued coal and oil and natural gas operations.

- **INTEREST EXPENSE AND OTHER INCOME**

Interest expense decreased approximately $7,200,000 with the net retirement of long-term debt in 1999 and early 2000. This decrease was partially offset by the reversal of interest expense in the fourth quarter 1999 related to an environmental liability, which was reduced with the sale of our electric generating assets in December 1999.

"Other income – net" increased approximately $33,700,000 principally due to Continental Energy's pretax gain of approximately $34,300,000 recognized in the second quarter resulting from the sale of its equity interest in the Brazos project in Cleburne, Texas, and increased interest income of approximately $10,000,000. "Other income – net" also includes approximately $1,500,000 of loss from unconsolidated telecommunications investments, as compared with approximately $9,800,000 of earnings for 1999. The decrease results primarily from anticipated losses from investments in two wireless joint ventures and a decrease of approximately $6,000,000 in dark-fiber transactions, mainly from the FTV joint venture.

- **INCOME TAXES**

Our effective income tax rate increased primarily for two reasons: (1) in accordance with the Electric Act, we are allowed to recognize as income accelerated amortizations of investment tax credits (ITCs) during the transition period if our return on equity drops below 9.5 percent and, as a result, we recognized in the fourth quarter 1999 approximately $8,300,000 of ITCs associated with our electric utility's business; and (2) we recognized as income approximately $10,000,000 in unamortized ITCs associated with the December 1999 sale of our electric generating assets to PPL Montana.

DISCONTINUED OPERATIONS

	Year Ended December 31		
	2000	**1999**	**1998**
	(Thousands of Dollars)		
DISCONTINUED OPERATIONS:			
Income from discontinued coal operations, net of income taxes..........................	$ 31,897	$ 37,400	$ 30,181
Income from discontinued oil and natural gas operations, net of income taxes..........	29,395	14,525	9,743
Gain on sale of discontinued oil and natural gas operations, net of income taxes..........	62,006	-	-
NET INCOME FROM DISCONTINUED OPERATIONS AVAILABLE FOR COMMON STOCK	$ 123,298	$ 51,925	$ 39,924

- **COAL OPERATIONS**

Income from our discontinued coal operations decreased mainly because of reduced revenues resulting from lower prices due to contract amendments, negotiated in 1998 that took effect in mid-2000, relating to the coal supply agreement between Western Energy and the owners of Colstrip Units 3 and 4 and lower sales volumes because of scheduled maintenance and unplanned outages at Colstrip.

- **OIL AND NATURAL GAS OPERATIONS**

Income from our discontinued oil and natural gas operations increased, despite only ten months of operation in 2000, primarily because of higher commodity prices. The 1999 write-downs of Canadian natural gas properties also contributed to the improved performance in 2000. We also recorded a gain of approximately $62,000,000, net of income taxes and a regulatory liability of approximately $32,500,000, relating to the sale of these properties. For more information on the sale of these properties and the accounting and regulatory implications, see Note 2, "Decision to Sell Energy Businesses," in the "Sale of Oil and Natural Gas Operations" section.

1999 COMPARED WITH 1998

- **CONSOLIDATED RESULTS**

Net income from continuing operations for 1999 decreased when compared with 1998. The main cause of the decrease was reduced earnings from unconsolidated investments resulting from several events relating to Continental Energy's equity investments that had materially positive results in 1998. In addition, income from telecommunications operations decreased – mainly because of the discount associated with a 1999 prepayment – and income from electric utility operations decreased compared with 1998.

Income from telecommunications operations decreased approximately 34 percent compared with 1998. In January 1999, a customer of Touch America exercised its option to prepay, with a discount, all amounts due for the remaining 12-year initial term of a capacity agreement. As a result, Touch America received $257,000,000 and Touch America's income from operations for 1999 was approximately $23,200,000 lower than it would have been without the discounted prepayment. Increased private line and long-distance revenues partially offset the effects of the prepayment.

The electric utility's operating income decreased approximately 11 percent compared with 1998 primarily due to increased volumes of surplus power sold in the secondary markets at higher prices, coupled with revenues earned from transmitting energy for customers who chose other suppliers. Higher expenses - especially SG&A expenses and electric transmission and distribution expenses - more than offset the increased revenues.

The natural gas utility's operating income increased approximately 10 percent compared with 1998 mainly because of customer growth and a 1998 decrease in revenues to reflect a rate refund under a PSC ruling.

Continental Energy's income from operations increased $7,000,000 mainly because of reduced amortization expenses reflecting expenses recorded in 1998 to reduce the value of an equity investment resulting from a contract buyout.

Interest expense decreased approximately $17,800,000 primarily for two reasons: (1) an adjusted environmental liability, and (2) funds were used from the telecommunications prepayment received in January 1999 to reduce short-term borrowings.

"Other income – net" decreased approximately $65,000,000 principally because of the following events, which had positive effects on Continental Energy's 1998 income: (1) a contract settlement between the Bonneville Power Administration and an independent power partnership in which Continental Energy was a partner; (2) the sale of Continental Energy's interest in the Lockport project in New York; and (3) the effects of the buyout of Continental Energy's interest in the Encogen Four project in New York.

- **TELECOMMUNICATIONS OPERATIONS**

Revenues

On January 16, 1999, a Touch America customer exercised its option to prepay, with a discount, all amounts due for the remaining 12-year initial term of a capacity agreement. As a result, Touch America received $257,000,000 and revenues from sales on Touch America's fiber optic network were approximately $23,200,000 less than they would have been had the customer not exercised its option. (The effect for a full year is approximately $24,000,000.) Touch America is recognizing the prepayment in revenues over the remaining 10-year initial term of the agreement.

The increase in operating revenues, after adjusting for the accounting effects of the prepayment, mainly consists of two elements. First, it reflects increased network services revenues of approximately $10,100,000 due to higher revenues from sales of fiber capacity. Second, retail sales revenues, including Internet service and equipment service revenues, increased approximately $7,800,000 as a result of increased long-distance customer and minute sales and customer growth.

The following table shows year-to-year changes in long-distance revenues for the previous two years.

	1999	1998
Revenues (Millions of Dollars) ...	$4	$3
Minutes sold	31%	43%
Price per minute	(9%)	(15%)
Customer growth	26%	61%

Expenses

O&M expenses increased approximately $7,700,000 as a result of increased network services and retail sales revenues. Depreciation and amortization expense increased approximately $2,000,000 as a result of an increase in plant.

❑ ELECTRIC UTILITY (INCLUDING COLSTRIP UNIT 4)

The following table categorizes revenues and volumes into "General Business Revenues," "Sales to Other Utilities," "Other," and "Intersegment." It also shows "Bundled Revenues" and "Distribution Only Revenues" separately for "General Business Revenues." While we no longer supply the electric energy for customers who have chosen other commodity suppliers, we continue to earn transmission and distribution revenues for moving their electric energy across our transmission and distribution lines. We reflect transmission revenues as "Other" revenues and distribution revenues as "Distribution Only Revenues."

	Revenues and Power Supply Expenses			Volumes		
	1999	**1998**	**%**	**1999**	**1998**	**%**
	(Thousands of Dollars)			(Thousands of MWh)		
REVENUES:						
General Business Bundled Revenues:						
Residential	$127,572	$125,523	2%	1,810	1,927	(6%)
Small Commercial, Small Industrial, and Government and Municipal	159,872	164,178	(3%)	2,474	2,793	(11%)
Large Commercial, Large Industrial	37,707	82,667	(54%)	1,095	2,158	(49%)
Irrigation and Street Lighting	15,254	14,683	4%	144	139	4%
Total	340,405	387,051	(12%)	5,523	7,017	(21%)
General Business Distribution Only Revenues:						
Small Commercial, Small Industrial, and Government and Municipal	2,837	179	1485%	128	9	1322%
Large Commercial, Large Industrial	13,622	2,034	570%	1,614	252	540%
Total	16,459	2,213	644%	1,742	261	567%
Total General Business Revenues	356,864	389,264	(8%)	7,265	7,278	-
Sales to Other Utilities	148,426	115,332	29%	5,023	3,591	40%
Other	27,752	21,931	27%	-	-	-
Intersegment	13,062	4,722	177%	66	125	(47%)
Total	$546,104	$531,249	3%	12,354	10,994	12%
POWER SUPPLY EXPENSES:						
Hydroelectric	$ 21,576	$ 22,266	(3%)	3,692	3,742	(1%)
Steam	54,969	50,952	8%	4,685	4,516	4%
Purchased Power and Other	127,245	126,985	-	4,626	3,758	23%
Total	$203,790	$200,203	2%	13,003	12,016	8%

General Business Revenues

Revenues from electric utility operations increased in 1999, while "General Business Revenues" decreased primarily because of a decrease in revenues from the Large Industrial Customer classification as these customers continued to choose other commodity suppliers. An increase in prices to recover the cost of public-purpose programs in accordance with the Electric Act lessened the effects of decreased revenues from Large Industrial Customers.

Sales to Other Utilities

Revenues from "Sales to Other Utilities" increased because of increased volumes sold in the secondary markets at higher average prices. We had more energy available to sell in the secondary markets because of increased plant availability as a result of less downtime for repairs and maintenance and lower consumption attributable to customers continuing to choose other suppliers.

Other

"Other" revenues increased mainly because of revenues earned for transmitting energy for customers who chose other suppliers. Prior to the Electric Act, we classified transmission revenues as "General Business Revenues." We now reflect transmission revenues from customers who chose other suppliers as "Other" revenues, while we still report transmission revenues from customers who have not chosen other suppliers as "General Business Revenues."

Intersegment

"Intersegment" revenues increased because of the revenues associated with MPT&M using our lines to transmit energy that it sold in the secondary markets. While we reflect sales in the secondary markets as "Sales to Other Utilities," as of July 1, 1998, we began reflecting revenues earned from the transmission of the energy sold to other utilities in the "Intersegment" line of the segmented schedule of revenues and expenses. The corresponding transmission volumes are the same volumes associated with the sale of energy in the secondary markets. Therefore, we report these volumes in the "Sales to Other Utilities" line in the table above.

Expenses

Power supply expenses increased primarily due to increased plant availability. Transmission and distribution expenses increased because of costs associated with using other companies' lines outside our service territory to transmit the energy sold in the secondary markets. Property taxes increased because of additional plant and higher assessed property values. Depreciation and amortization expense decreased because of expenses incurred in 1998 associated with software costs and property held for future use.

SG&A expenses increased approximately $14,400,000 mainly because of the following items:

- An increase of approximately $7,900,000 for energy efficiency and public-purpose programs to comply with the USBC requirements of the Electric Act. In accordance with the Electric Act, we collect these costs through a separate component of rates.

- Costs of approximately $2,000,000 incurred to train staff and to reengineer business processes to implement the new ERP information system and similar costs of approximately $3,800,000 for the ECC information system.

- Increases in other administrative costs of approximately $2,700,000, which were mostly offset by decreased benefit expenses of approximately $2,000,000 relating to the curtailment of a benefit plan in the prior year.

❑ NATURAL GAS UTILITY

The following table categorizes revenues and volumes related to our natural gas utility.

	Revenues			Volumes		
	1999	**1998**	**%**	**1999**	**1998**	**%**
	(Thousands of Dollars)			(Thousands of Dkt)		
REVENUES:						
Residential	$63,921	$61,666	4%	12,657	11,505	10%
Small Commercial, Small Industrial, and Government and Municipal	30,329	31,842	(5%)	5,874	6,006	(2%)
General Business Revenues	94,250	93,508	1%	18,531	17,511	6%
Less: Gas Supply Cost Revenues (GSC)	32,759	31,940	3%	-	-	-
General Business Revenues without GSC	61,491	61,568	-	18,531	17,511	6%
Sales to Other Utilities	687	606	13%	229	200	15%
Transportation	15,197	14,844	2%	24,426	27,320	(11%)
Other	1,282	(1,604)	180%	-	-	-
Total	$78,657	$75,414	4%	43,186	45,031	(4%)

Revenues

Increased revenues from customer growth and increased rates to recover higher gas-supply costs were offset by a decrease in revenues from industrial customers continuing to choose other commodity suppliers. As mentioned in the "2000 Compared With 1999" discussion, all of our former Large Industrial and Large Commercial customers have now chosen other commodity suppliers. "Other" revenues increased because of a 1998 decrease in revenues to reflect a rate refund in compliance with a PSC ruling.

Expenses

SG&A expenses increased chiefly because of expensed costs for implementing the ERP and ECC information systems. An increase relating to energy efficiency and public-purpose programs mostly offset a decrease in other administrative costs.

❑ **CONTINENTAL ENERGY**

Continental Energy's operating income increased $7,000,000 mainly as a result of lower amortization expense in 1999 compared to 1998 because Continental Energy recorded amortization expense of approximately $5,900,000 in 1998 to reflect the reduced value of its investment in the Encogen Four project as a result of the contract buyout.

❑ **INTEREST EXPENSE AND OTHER INCOME**

With the sale of our generating assets, we will no longer be responsible for mitigating costs associated with Kerr Project operations after the date of the sale. We had previously recorded the present value of mitigation expenditures over the life of the license. From the date of the initial entry through the date of the sale, interest expense had been recorded to adjust the mitigation liability to current dollars. The mitigation liability has now been adjusted, and accrued interest expense was reversed. This adjustment to interest expense, coupled with the use of funds from the January 1999 telecommunications prepayment to reduce short-term borrowings, accounted for the majority of the decrease in interest expense of approximately $17,800,000. For additional information on the Kerr Project, see Note 13, "Contingencies."

"Other income – net" decreased approximately $65,000,000 mainly because of reduced earnings from unconsolidated investments. Earnings from unconsolidated independent power investments decreased approximately $68,500,000 mainly because of the three events discussed at the beginning of the MD&A section, "1999 Compared With 1998," under "Interest expense and other income - net."

Partially offsetting these reduced earnings from unconsolidated investments was increased interest income on investments of approximately $4,300,000.

❑ **INCOME TAXES**

The ITCs that we recognized in the fourth quarter 1999, as mentioned in the discussion of "2000 Compared With 1999," accounted for the majority of the decrease in our effective income tax rate for 1999 as compared with 1998.

❑ **COAL**

Income from coal operations increased due to higher revenues resulting from increased tons sold and the effects of a one-time refund issued in the third quarter 1998 by Western Energy to Colstrip Units 3 and 4 customers that resulted in decreased 1998 revenues.

❑ OIL AND NATURAL GAS

Increased income from oil and natural gas operations resulted from higher oil and natural gas prices and increased natural gas volumes sold. These higher prices and increased volumes more than offset 1999 decreases in oil volumes sold and write-downs of our Canadian natural gas properties.

LIQUIDITY AND CAPITAL RESOURCES

❑ OPERATING ACTIVITIES

Net cash used for operating activities was $55,877,000 in 2000, compared to net cash provided by operating activities of $660,183,000 in 1999, and $255,677,000 in 1998. The current year decrease of $716,060,000 was attributable mainly to the following:

- A $257,000,000 prepayment received in January 1999 from a Touch America customer and a $106,000,000 payment received in December 1999 as a result of the termination of a purchase-power agreement with the LADWP and the establishment of a new agreement. We used cash from the telecommunications prepayment to reduce long-term debt and short-term borrowings and pay taxes on the prepayment and on expected gains resulting from the sale of our electric generating assets;
- Net proceeds in excess of book value of $219,726,000 received in December 1999 from the sale of our electric generating assets;
- Decreased income taxes payable mainly because of taxes paid on proceeds received from the October 31, 2000 sale of our oil and natural gas businesses; and
- Increased accounts and notes receivable as a result of the June 30, 2000 acquisition of telecommunications properties.

❑ INVESTING ACTIVITIES

Net cash used for investing activities was $133,877,000 in 2000, compared to net cash provided by investing activities of $306,504,000 in 1999 and net cash used for investing activities of $159,552,000 in 1998. The current year decrease of $440,381,000 was due primarily to increased capital expenditures, mainly related to the acquisition of telecommunications properties and joint network construction with AT&T, and a decrease in proceeds from the sales of property and investments related to the 1999 sale of our electric generating assets. Proceeds received from the sale of our oil and natural gas businesses partially offset this decrease.

Forecasted capital expenditures for 2001 and capital expenditures during the prior three years are as follows:

	Forecasted		*Actual*	
	2001	**2000**	**1999**	**1998**
		(Thousands of Dollars)		
Continuing Operations:				
Telecommunications	$ 448,000	$554,119	$ 153,617	$ 56,203
Utility	20,000[1]	50,264	63,618	83,927
IPG	-	12,230	-	10,725
Other	-	27,603	15,957	189
Total	$ 468,000	$ 644,216	$ 233,192	$ 151,044

[1] The utility's capital expenditures for 2001 are forecast through the anticipated closing of the sale of our utility business. This sale is targeted to close approximately three months after the proxy statement/prospectus is filed and becomes effective.

Touch America expects to invest $448,000,000 in 2001. The majority of the capital expenditures will be invested to expand and develop Touch America's fiber optic network. Approximately $321,000,000 will be invested in fiber installation to build out the estimated 26,000-mile network, with another $86,000,000 invested in electronics to light the network. See Item 1, “Business,” under the “Telecommunications Operations” section, and Note 14, “Commitments,” for further discussion of Touch America’s projects and commitments. We intend to invest the majority of the utility’s capital budget in our electric and natural gas transmission and distribution systems.

We estimate that internally generated funds for 2001, including proceeds from the sale of our remaining energy businesses, will average 100 percent of Touch America’s capital expenditures, and 481 percent of our utility’s capital expenditures.

- **FINANCING ACTIVITIES**

Net cash used for financing activities was $246,236,000 in 2000, compared to $422,396,000 in 1999 and $88,779,000 in 1998.

For information regarding our repurchase of common stock, see Note 7, “Common Stock.”

Dividends paid on common and preferred stock were $67,053,000 in 2000, $90,902,000 in 1999, and $91,598,000 in 1998. During 2000, our regular quarterly dividend level was $0.20 per share of outstanding stock or $0.80 per share on an annual basis. As discussed in Item 1, “Business,” our Board of Directors voted in October 2000 to eliminate dividend payments on common stock effective the first quarter 2001, reflecting our transition to a telecommunications enterprise. The final quarterly dividend on our common stock was $0.20 per share, payable to shareholders of record on November 1, 2000.

Our consolidated borrowing ability under our Revolving Credit and Term Loan Agreements was $490,000,000, of which $390,000,000 was unused at December 31, 2000. On April 4, 2000, our $100,000,000 Revolving Credit Agreement for some of our nonutility operations terminated with no amounts outstanding. In 2000, we entered into a $30,000,000 Revolving Credit Agreement that expires on June 28, 2001 and a $200,000,000 90-Day Credit Agreement for use in our telecommunications operations that expired on November 8, 2000. At that time, Touch America entered into a five-year $400,000,000 Senior Secured Credit Facility (Credit Facility) consisting of a $200,000,000 Revolving Credit Agreement and a $200,000,000 Term Loan Agreement for use in our telecommunications operations.

On November 29, 2001, our $60,000,000 Revolver related to our utility operations expires. Certain uncommitted borrowing lines under which we have $21,000,000 outstanding at September 30, 2001, expire by the end of November 2001. We currently intend to issue, subject to market conditions, $150,000,000 in First Mortgage Bonds during the month of November 2001. Proceeds of the offering will be used to repay the $60,000,000 outstanding under our committed credit line, repay other short-term borrowings, repay an intercompany loan between Montana Power and Entech, Inc., our wholly owned subsidiary and Touch America’s parent company, and redeem our ESOP Notes. The remaining balance will be used for existing cash requirements. If we are unable to complete our proposed bond offering we will seek other sources of funds, including funds from the lending banks under our bank facilities although there can be no assurances that funds will be available on acceptable terms.

We believe we currently have the capacity to issue additional First Mortgage Bonds in an amount sufficient to meet our foreseeable financing requirements.

Based on financial performance for the twelve-month period ending September 30, 2001, Touch America is not in compliance with financial covenants under its Credit Facility requiring Touch America to maintain a ratio of total debt to EBITDA (earnings before interest, taxes, depreciation and amortization) of not more than 4.50:1 and a ratio of senior secured debt to EBITDA of not more than 3.50:1. On November 14, 2001, Touch America received a 30-day waiver of the requirement to comply with the financial covenants from the lending banks under the Credit Facility. The waiver is conditional upon Montana Power Company repaying to Entech, Inc., by November 30, 2001, at least $25,000,000 of the intercompany loan discussed above. The proceeds will be used for general corporate purposes of Touch America. As a condition to the waiver, Touch America has agreed - among other things – to an increase in the pricing of the Credit Facility, including a 50 basis point increase in the commitment fee, and that Touch America may not make further borrowings under its revolving credit facility.

Touch America's Credit Facility is currently its principal source of funds to meet capital requirements. As a result of Touch America's failure to comply with the Credit Facility financial covenants discussed above, and based on the terms of the waiver entered into with the lending banks under the facility, Touch America may not make further borrowings under the Credit Facility at the present time. Touch America is seeking additional funds from the lending banks under the Credit Facility to meet its near term cash requirements but there can be no assurances that additional funds will be made available or if they are, that the timing of the availability will allow Touch America to meet its commitments. Touch America does not believe that it currently has access to the capital markets on reasonable terms to meet its capital requirements. If Touch America does not reach agreement with the lending banks under its Credit Facility or receive additional funds from other sources, Touch America will be unable to meet its obligations and could experience a material adverse impact on its financial condition and face challenges to its financial viability. The lending banks under the Credit Facility do not have recourse against the Company's assets not attributable to Touch America.

Our long-term debt as a percentage of capitalization was 20 percent during 2000, 35 percent in 1999, and 37 percent in 1998. The current year ratio decreased due to the use of the generation sale proceeds to repurchase long-term debt. Approximately $169,054,000 of long-term debt will mature during the year 2001. The ratio could decrease during 2001 with the proceeds from the sales of our energy businesses available to repurchase long-term debt. We have also entered into long-term lease arrangements and other long-term contracts for sales and purchases that are not reflected on the Consolidated Balance Sheet. For additional information on the long-term lease arrangements and other long-term contracts, see Note 14, "Commitments."

For further information on our financing activities, see Note 10, "Long-Term Debt," and Note 11, "Short-Term Borrowing."

SEC RATIO OF EARNINGS TO FIXED CHARGES

For the year ended December 31, 2000, our ratio of earnings to fixed charges was 2.39 times compared to 2.49 times for 1999 and 2.84 times for 1998. We used net income and income taxes only from continuing operations to calculate earnings. Fixed charges include interest from continuing and discontinued operations, the implicit interest of Colstrip Unit 4 rentals, and one third of all other rental payments.

INFLATION

We believe that, at currently anticipated levels, inflation will not materially affect our results of operations.

ENVIRONMENTAL ISSUES

For a discussion of environmental issues and how they affect us, see Item 1, "Business," under the "Environmental Issues" section.

NEW ACCOUNTING PRONOUNCEMENTS

For information on new accounting pronouncements and how they affect us, see Note 16, "New Accounting Pronouncements."

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our energy commodity activities and other investments and agreements expose us to the market risks associated with fluctuations in commodity prices, interest rates, and changes in foreign currency translation rates. We specify below what these risks are to our business and estimate what could occur under various adverse market conditions. Because we base our estimates on assumptions only, actual results of operations could differ materially from our estimates. These disclosures indicate only reasonably possible losses and do not necessarily indicate expected future losses.

TRADING INSTRUMENTS

We discuss the derivative financial instruments that we use to manage commodity price risk in our electric and natural gas utility business- in Note 1, "Summary of Significant Accounting Policies," in the "Derivative Financial Instruments" section, in Note 13, "Contingencies," in the "Long-Term Power Supply Agreements" section, and below in "Other-Than-Trading Instruments." We do not use derivative financial instruments to hedge against exposure to fluctuations in interest rates or foreign currency exchange rates. However, we formerly had investments in independent power partnerships, some of which had used derivative financial instruments to hedge against interest rate exposure on floating rate debt. For further information on the February 21, 2001 sale of our independent power production business, see Note 2, "Decision to Sell Energy Businesses," in the "Sale of Continental Energy" section.

❑ **SUMMARY OF 1999 AND COMPARISON OF 2000 WITH 1999**

At December 31, 1999, we included derivative financial contracts relating to crude oil, natural gas, and natural gas liquids in the calculation of our Value at Risk limit, which was less than $2,000,000. At December 31, 2000, we no longer owned oil and natural gas operations and, therefore, had no crude oil, natural gas, or natural gas liquids trading and marketing operations.

OTHER-THAN-TRADING INSTRUMENTS

❑ **COMMODITY PRICE EXPOSURE**

Continuing Operations

Qualifying Facilities

The Public Utilities Regulatory Policies Act (PURPA) requires a public utility to purchase power from QFs at a rate equal to what it would pay to generate or purchase power. The electric utility has 15 long-term QF contracts with expiration terms ranging from 2003 through 2032 that require us to make payments for energy capacity and energy received at prices established by the PSC. Because the wholesale electric energy market does not extend beyond 18 months, and we do not have bids on the sale of the QFs, we cannot make a meaningful estimation of the QFs' market value at December 31, 2000. These contracts are included in our Tier II filing with the PSC and anticipated sale of our utility business to NorthWestern Corporation.

Wholesale Transition Service Agreements

Our electric utility also entered into two Wholesale Transition Service Agreements (WTSAs), effective December 17, 1999, with PPL Montana. These agreements enable us to fulfill our obligation to supply electric energy until July 2002 to those customers who have not chosen another supplier. Both agreements set the price of electric energy at a Mid-Columbia (Mid-C) index, with a monthly floor and an annual cap, and thus limit our exposure to price fluctuations. Under both agreements, the annual cap is $22.25/MWh, which has been in effect for most of 2000 because wholesale electric energy prices in the Pacific Northwest have been higher than this amount.

For a discussion of the PSC's March 15, 2001 issuance of a Notice of Commission Action and Opportunity to Comment, stating the PSC's belief that it not only has continuing jurisdiction over our utility that provides fully regulated services to our customers, but also over the electric generating assets that we sold to PPL Montana in December 1999, and various energy-related proposals currently under consideration by the Montana Legislature regarding the supply and cost of electric energy in Montana, see Item 1, "Business," in the "Notice of PSC Action and Legislative Proposals" section, and Item 7, MD&A, in the "Utility Operations" section, under "Electric Utility (including Colstrip Unit 4)." We cannot predict the ultimate outcome of these matters or their potential effect on our consolidated financial position, results of operations, or cash flows.

Colstrip Unit 4

We sell the leased share of Colstrip Unit 4 generation principally to Duke Energy Trading & Marketing (DETM) and to Puget Sound Energy (Puget) under agreements that expire at the same time as the initial term of our sale-leaseback agreement of Colstrip Unit 4. In December 1999, we agreed with the Los Angeles Department of Water & Power (LADWP) to terminate the 11 remaining years of the then-existing agreement, and entered into a new agreement to provide LADWP 111 MWs of capacity and energy from December 1999 to December 2010, at scheduled rates. We received $106,000,000 from the LADWP as consideration for the termination and establishment of the agreements, and LADWP immediately assigned the new agreement to DETM. The $106,000,000 reimbursed us for DETM's share of the fixed cost associated with the leased property and was recorded by us as deferred revenue, to be recognized over the life of the agreement. The scheduled rates of the new agreements with DETM and Puget are based on an estimation of Colstrip Unit 4's variable costs over the life of the agreements.

These agreements expose us to commodity price risk in two ways:

- Because the DETM agreement has a capacity requirement, we may have to purchase electric energy at Mid-C market rates, when we cannot produce it ourselves, and the cost of these purchases could exceed our DETM sales revenues.
- Our variable costs – our operational and fuel costs – could exceed the revenues allowable under both the DETM and Puget rate schedules.

Based on the net present value of forecasted income discounted at our December 31, 2000 short-term borrowing rate of 8.05 percent, we estimate that the fair market value of these agreements would be a negative $48,200,000, which approximates the net liability recorded for our investment in Colstrip Unit 4 at December 31, 2000.

Large Industrial Customers

Several long-term power supply agreements with large industrial customers expose us to commodity price risk, to the extent that a portion of the electric energy that we are required to sell to these customers at fixed rates is purchased by us at rates indexed to a wholesale electric market, which can be higher than the fixed sales rate. We seek to mitigate our exposure to losses on these agreements with financial derivative instruments called "price swaps" and offsetting electric energy purchase and sales agreements.

Since June 1998, we have had a price swap agreement with our industrial customer whose agreement exposes us to most of the risk. The price swap converts a maximum of 43 MWs of the Mid-C index price of our supply agreement with that customer to a fixed price through May 31, 2001. At the same time, we entered into a separate fixed-price purchase and related Mid-C index-based sale of a maximum of 40 MWs of electric energy with two different counterparties, through May 31, 2001, to hedge electric energy purchased at the Mid-C index used to supply our industrial customers. Because the Mid-C index price is used for both the MWs purchased for the large industrial customer and the MWs sold to one of the counterparties, an increase in the Mid-C index would not change the effectiveness of our hedge of 40 MWs. However, if our industrial customer's consumption were to exceed a volume requiring more than the 40 MWs hedged, we would be exposed to additional losses from supplying this customer.

During the third quarter 2000, our industrial customer whose agreement exposes us to most of the risk increased its electric energy consumption by approximately 30 percent, and wholesale electric prices increased substantially. Because of these two events, the expenses of supplying electric energy to that industrial customer and, to a lesser extent, other industrial customers exceeded the associated revenues earned from these customers, the price swap, and the fixed-price purchase/Mid-C sales hedge by approximately $8,400,000 for the third quarter. To mitigate future losses, we entered into another price swap with a counterparty that effectively hedges 35 MWs of the anticipated Mid-C based purchases to supply our industrial customers through March 31, 2001. Because that swap effectively hedges approximately 40 percent of the cost of purchasing 35 MWs at Mid-C for our customers, a hypothetical increase in the Mid-C index would not change the swap's effectiveness.

Based on the anticipated effects of the existing purchase and sales agreements, the financial swaps, and customer usage estimates, we expect to experience losses of approximately $4,000,000 in the first quarter 2001. If we continue to purchase electric energy at index-based market rates, or do not have other effective swaps in place, we estimate that the losses on these industrial customers – based on the above usage estimates and on forward price projections and broker quotations as of December 29, 2000 – could aggregate approximately $25,000,000 in the second quarter 2001 and more in subsequent quarters. Because of the volatility of the electric energy market in the western United States, particularly in the Pacific Northwest, and future possibilities of supplying these customers from alternative sources, we believe that estimating losses that we may incur beyond the second quarter 2001 would not be meaningful.

We continue to seek other opportunities to mitigate the commodity price risk associated with our power supply agreements, although we cannot assure that these efforts will be successful. For more specific information about these events, see Note 13, "Contingencies," in the "Long-Term Power Supply Agreements" section.

Natural Gas Take-or-Pay Contracts

Our 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 five of these contracts, with expirations between 2001 and 2006, most of which price natural gas on a variant of the Alberta Energy Company "C" Hub (AECO-C) index. Because we expect to recover the reasonable cost associated with these contracts in future rates, we do not believe that these contracts subject us to commodity price risk.

Cobb Storage Sales

By drilling wells and adding compression at our Cobb storage reservoir, we are able to sell natural gas that had been held in reserve to provide firm storage deliverability to our customers. We therefore contracted to sell, from October 2000 through March 2001, 1,760,000 dekatherms from that reservoir at a monthly price based on the AECO-C index. To mitigate our exposure to fluctuations of the market index price, we entered into a swap agreement with a counterparty that effectively converts that index price to a fixed price for 903,000 dekatherms associated with these sales from December 2000 through February 2001. For December 2000, we recognized a loss of approximately $300,000 on the swap and a profit of approximately $1,200,000 on the sale of the Cobb storage natural gas.

Based on the AECO-C forward prices at December 29, 2000, we estimate a loss of $3,000,000 on the swap to offset profits of $4,900,000 on the sale through February 2001. Since the swap agreement is an effective hedge of the Cobb storage sales, a hypothetical increase in the AECO-C would increase the loss on the swap and the profit on the sale by the same amount – approximately $600,000.

General

Some of these electric and natural gas agreements have liquidated damage clauses that require the non-performing party to pay the other party the positive difference between the market and contract prices plus transportation and other fees. We believe that the possibility of non-performance is remote and, therefore, have not calculated its financial effect.

We expect to recover all reasonable costs associated with the QF contracts through competitive transition charges (CTCs), all reasonable costs associated with the WTSA contracts in the electric restructuring process, and the reasonable costs associated with the take-or-pay contracts through future natural gas rates. Therefore, we do not expect these contracts to expose us to market risks related to commodity price fluctuations. However, recovery of the costs associated with these contracts is subject to regulatory lag or possible disallowance. For additional information, see Note 5, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

Our agreements to supply electric energy to DETM and Puget expose us to the possibility of unrecoverable losses primarily because of the two reasons discussed above in the "Colstrip Unit 4" section: (1) to fulfill our supply obligations, we could be required to purchase electric energy at market-based rates higher than the fixed sales rates that we receive pursuant to these agreements, and (2) we could experience higher-than-expected fuel costs at Colstrip Unit 4. As discussed above in the "Large Industrial Customers" section, our long-term power supply agreements with several large industrial customers subject us to the possibility of unrecoverable losses because we fulfill our obligations under these contracts by purchasing electric energy at market-based rates, which could be higher than the fixed sales rates we receive pursuant to these long-term power supply agreements.

Discontinued Coal Operations

Northwestern Resources has a full-lignite requirements supply agreement (LSA) through August 2015 for the delivery of lignite to two mine-mouth electric generating facilities. The contract currently provides for the reimbursement of certain mining costs as well as management and dedication fees and, therefore, does not expose us to commodity price risk. Under a settlement reached in August 1999, the pricing structure will change July 1, 2002 to one driven by the market for Powder River Basin (PRB) coal adjusted for transportation and other costs. We estimate that, after mid-2002, a hypothetical 10 percent decrease of the PRB market price adjusted for transportation costs would reduce annual revenues by approximately $3,000,000.

Western Energy also has full-requirements contracts for the sale of coal to the four mine-mouth electric generating plants at Colstrip. The contract for Units 1 and 2 provides for a price re-opener in 2001 to adjust prices that reflect changes in mining costs and provide a reasonable profit. Because our mining costs are not directly tied to market price changes, the Units 1 and 2 contract is not subject to commodity price risk. The contract for Colstrip Units 3 and 4 requires that we constantly evaluate alternative supplies. However, neither Western Energy nor the Colstrip Steam Electric Station has a unit train off-loading facility. Because the prices of alternative supplies must include the substantial cost of constructing this facility, a hypothetical 10 percent decrease in the prices of these competitive coal supplies would not materially affect us.

For more information on the pending sale of our coal businesses, which we expect to close at approximately the beginning of the second quarter 2001, see Note 2, "Decision to Sell Energy Businesses."

❑ INTEREST RATE EXPOSURE

SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," defines instruments readily convertible to cash as "financial instruments." These financial instruments principally include our cost-basis investments in independent power projects, the reclamation fund, mandatorily redeemable preferred securities, and long-term debt. All of these instruments are exposed to potential loss in fair value from adverse changes in interest rates. Assuming the fair values estimated for the SFAS No. 107 analysis and a hypothetical 10 percent adverse change in interest rates, we estimate that (1) the potential loss at the December 31, 2000 fair value of the reclamation fund and cost-based investments would be immaterial; and (2) the potential loss at the December 31, 2000 fair values of the mandatorily redeemable preferred securities and long-term debt would be approximately $4,900,000 and $14,400,000, respectively. For more information about fair valuation, see Note 1, "Summary of Significant Accounting Policies," in the "Fair Value of Financial Instruments" section.

❑ FOREIGN CURRENCY EXPOSURE

Our primary foreign currency exposure resulted from (1) our former Canadian subsidiaries – Altana Exploration Company and Altana Exploration Ltd. – exploring for, producing, gathering, processing, transporting, and marketing natural gas and crude oil in Canada, and (2) our former affiliate, MPT&M, trading and marketing natural gas in Canada. We sold these operations on October 31, 2000 and, consequently, reduced our exposure to adverse foreign currency fluctuations to an insignificant level.

❑ SUMMARY OF 1999 AND COMPARISON OF 2000 WITH 1999

At December 31, 2000, our businesses exposed us to most of the same kinds of risks that we reported at December 31, 1999. We summarize below the significant differences between our discussion of those risks in 1999 and 2000:

- Because we had buy-out bids in 1999, we were able to estimate that the QF contracts could result in above-market costs of between $300,000,000 and $500,000,000 throughout their duration. Without such bids in 2000, however, we could not reasonably estimate their fair market value.

- Based on our average borrowing rate for 1999, the fair market value calculation of the DETM and Puget agreements was a negative $58,800,000, which approximated the net liability recorded for our investment in Colstrip Unit 4 as of December 31, 1999. This negative value reflects the prepayment received in December 1999 from the LADWP.

- We could not reasonably estimate our probable loss resulting from supply agreements with large industrial customers at December 31, 1999 because we were uncertain about the supply requirements of those customers and the arrangements to serve their requirements. In 2000, however, we believe that usage estimates provided by certain large industrial customers and a price swap effectively hedging 35 MWs of the anticipated market-based purchases to supply the industrial customers made possible a reasonable estimate of probable losses for late 2000 and early 2001.

- In 1999, we discussed Continental Energy's equity interests in various electric generation and co-generation projects and estimated their fair market value at $110,000,000 as of December 31, 1999. Because the sale of Continental Energy closed on February 21, 2001, we did not discuss Continental Energy's equity interest in these projects or compute their fair market value as of December 31, 2000.

- In 1999, we estimated that a hypothetical 10 percent increase in interest rates would decrease the fair market value of our long-term debt by $26,500,000 and, in 2000, we estimated that it would decrease that fair market value by $14,400,000. The estimated decrease was less in 2000, principally because we repurchased approximately $249,800,000 of long-term debt in 2000.