DEVON ENERGY CORP/DE

FORM 8-K
(Current report filing)

Filed 07/17/02 for the Period Ending 01/24/02

Address	333 W. SHERIDAN AVENUE OKLAHOMA CITY, OK 73102
Telephone	4055528183
CIK	0001090012
Symbol	DVN
SIC Code	1311 - Crude Petroleum and Natural Gas
Fiscal Year	12/31

DEVON ENERGY CORP/DE

FORM 8-K
(Unscheduled Material Events)

Filed 7/17/2002 For Period Ending 1/24/2002

Address	20 N BROADWAY STE 1500
	OKLAHOMA CITY, Oklahoma 73102
Telephone	405-235-3611
CIK	0001090012
Industry	Oil & Gas Operations
Sector	Energy
Fiscal Year	12/31

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 REPORT (DATE OF EARLIEST EVENT REPORTED) JULY 17, 2002
(January 24, 2002)

DEVON ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

Delaware

(State or Other Jurisdiction of Incorporation)

000-30176	73-1567067
(Commission File Number)	(I.R.S. Employer Identification No.)

20 North Broadway, Suite 1500, Oklahoma City, Oklahoma	73102-8260
(Address of Principal Executive Offices)	(Zip Code)

(405) 235-3611
(Registrant's Telephone Number, Including Area Code)

N/A
(Former Name or Former Address, if Changed Since Last Report)

ITEM 5. OTHER EVENTS

On January 24, 2002, Devon Energy Corporation ("Devon") completed its acquisition of Mitchell Energy & Development Corp. ("Mitchell"). On January 29, 2002, Devon filed a Form 8-K that included Mitchell's consolidated financial statements as of September 30, 2001 and for the nine months then ended, as well as pro forma financial statements for the same periods.

Included in this Form 8-K are updated financial statements including Mitchell's audited consolidated financial statements as of December 31, 2001 and for the year then ended, as well as pro forma financial statements for the same period.

The consolidated financial statements of Mitchell and its subsidiaries as of December 31, 2001 and 2000 and for the years ended December 31, 2001, 2000 and 1999, that are included in this Form 8-K have been audited by Arthur Andersen LLP, independent public accountants, as indicated in their report included herein.

This Form 8-K is incorporated by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908 and 333-85553) on Form S-8, the Registration Statement (File No. 333-75206) on Form S-4, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-50034 and 333-83156) on Form S-3 of Devon. Representatives of Arthur Andersen LLP are not available to consent to the inclusion of their report on Mitchell's consolidated financial statements in the aforementioned Registration Statements, and we have dispensed with the requirement to file their consent in reliance upon Rule 437a of the Securities Act of 1933. Because Arthur Andersen LLP has not consented to the inclusion of their report in the aforementioned Registration Statements, you may not be able to recover against Arthur Andersen LLP under Section 11 of the Securities Act for any untrue statements of a material fact contained in Mitchell's consolidated financial statements audited by Arthur Andersen LLP or any omissions to state a material fact required to be stated therein or necessary to make the statements therein not misleading.

ITEM 7. FINANCIAL STATEMENTS AND EXHIBITS.

(a) Financial Statements of Businesses Acquired.

Audited Consolidated Financial Statements of Mitchell Energy & Development Corp. and subsidiaries as of December 31, 2001 and 2000 and for the years ended December 31, 2001, 2000 and 1999

(b) Pro Forma Financial Statements.

Unaudited Devon Energy Corporation Pro Forma Combined Financial Statements as of December 31, 2001 and for the year then ended

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

(THIS REPORT IS A COPY OF A REPORT ISSUED BY ARTHUR ANDERSEN LLP ON MARCH 13, 2002. REPRESENTATIVES OF ARTHUR ANDERSEN LLP ARE NOT AVAILABLE TO REISSUE THIS REPORT FOR THIS FORM 8-K.)

To Mitchell Energy & Development Corp.:

We have audited the accompanying consolidated balance sheets of Mitchell Energy & Development Corp. (a Texas corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of earnings, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Mitchell Energy & Development Corp. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Houston, Texas
March 13, 2002

Mitchell Energy & Development Corp. and Subsidiaries
CONSOLIDATED BALANCE SHEETS (Note 13)
DECEMBER 31, 2001 AND 2000
(dollar amounts in thousands)

	2001	2000
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 15,218	$ 23,451
Trade receivables (net of allowance for doubtful accounts of $2,800 and $381)	111,428	221,946
Federal income taxes receivable	41,434	--
Inventories (at lower of cost or market)	15,471	17,636
Other	11,568	5,198
Total current assets	195,119	268,231
PROPERTY, PLANT AND EQUIPMENT (at cost less accumulated depreciation, depletion and amortization of $1,757,361 and $1,559,427 - Note 2)	1,658,612	1,206,005
LONG-TERM INVESTMENTS AND OTHER ASSETS	57,707	45,529
	$1,911,438	$1,519,765
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Current maturities of long-term debt (Note 4)	$ 62,920	$ --
Oil and gas proceeds payable	89,245	166,221
Accounts payable	98,743	79,248
Accrued liabilities	56,449	58,670
Total current liabilities	307,357	304,139
LONG-TERM DEBT (Note 4)	363,055	300,342
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred income taxes (Note 5)	296,750	203,919
Retirement obligations (Note 8)	77,526	71,733
Other	23,731	19,446
	398,007	295,098
COMMITMENTS AND CONTINGENCIES (Notes 3, 6 and 8)		
STOCKHOLDERS' EQUITY (Note 10)		
Preferred stock, $.10 par value (authorized 10,000,000 shares; none issued)		
Common stock, $.10 par value (authorized 200,000,000 shares) (Note 10)	5,386	5,386
Additional paid-in capital	155,464	148,154
Retained earnings	766,379	565,132
Other comprehensive loss	(11,321)	(8,896)
Treasury stock, at cost	(72,889)	(89,590)
	843,019	620,186
	$1,911,438	$1,519,765

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

Mitchell Energy & Development Corp. and Subsidiaries
CONSOLIDATED STATEMENTS OF EARNINGS
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(in thousands except per-share amounts)

	2001	2000	1999
REVENUES			
Exploration and production	$ 656,404	$ 531,213	$254,009
Gas services	1,162,532	1,135,899	623,459
	1,818,936	1,667,112	877,468
OPERATING COSTS AND EXPENSES (including personnel reduction program costs of $15,652 in 1999 - Note 9)			
Exploration and production (includes $26,029 proved property impairment charge in 2001; net of litigation provision reversals of $1,200 in 2000 and $14,000 in 1999 - Note 9)	342,782	239,628	177,862
Gas services (including an asset impairment charge of $10,762 in 2000 - Note 9)	1,087,741	1,007,944	548,533
	1,430,523	1,247,572	726,395
SEGMENT OPERATING EARNINGS (Note 9)	388,413	419,540	151,073
General and administrative expense (including personnel reduction program costs of $8,848 in 1999 - Note 9)	32,731	43,739	37,626
TOTAL OPERATING EARNINGS	355,682	375,801	113,447
OTHER EXPENSE			
Interest expense	22,720	28,765	34,499
Capitalized interest	(7,534)	(2,948)	(2,029)
Gains from disposition of property, plant and equipment (including gains of $4,884 from an asset exchange in 2000 - Note 3, and $11,527 from the sale of Hell's Hole area properties in 1999 - Note 14)	(411)	(5,022)	(16,888)
Other (income) expense	1,969	(2,951)	(4,133)
	16,744	17,844	11,449
EARNINGS BEFORE INCOME TAXES	338,938	357,957	101,998
INCOME TAXES (net of $12,830 prior years' Section 29 tax credits and $6,293 reversal of certain prior years' deferred taxes in 2000) (Note 5)	111,139	100,811	34,664
NET EARNINGS	$ 227,799	$ 257,146	$ 67,334
EARNINGS PER SHARE (Note 12)			
Basic	$ 4.56	$ 5.22	$ 1.37
Diluted	4.48	5.13	1.37
AVERAGE COMMON SHARES OUTSTANDING			
Basic	50,000	49,291	49,117
Diluted	50,889	50,084	49,223

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

Mitchell Energy & Development Corp. and Subsidiaries
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (Note 13)
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(dollar amounts in thousands)

DOLLAR AMOUNTS	Total	Common Stock	Additional Paid-in Capital	Retained Earnings	Other Compre-hensive Loss	Treasury Stock
BALANCE, DECEMBER 31, 1998................	$341,282	$5,386	$143,636	$303,774	$(7,364)	$(104,150)
Net earnings..............................	67,334	-	-	67,334	-	-
Minimum pension liability adjustment (net of income taxes of $794)..........	1,474	-	-	-	1,474	-
Comprehensive income................	68,808					
Cash dividends (48 cents per share on Class A and 53 cents per share on Class B)............................	(24,916)	-	-	(24,916)	-	-
BALANCE, DECEMBER 31, 1999................	385,174	5,386	143,636	346,192	(5,890)	(104,150)
Net earnings..............................	257,146	-	-	257,146	-	-
Minimum pension liability adjustment (net of income taxes of $1,619)........	(3,006)	-	-	-	(3,006)	-
Comprehensive income................	254,140					
Regular cash dividends (cents per share - 25.25 on Class A, 26.5 on Class B and 26.5 on combined shares)...	(25,895)	-	-	(25,895)	-	-
Special cash dividends (25 cents per share each on Class A and Class B shares)........................	(12,311)	-	-	(12,311)	-	-
Treasury stock purchases..................	(2,768)	-	-	-	-	(2,768)
Exercises of stock options................	21,846	-	4,518	-	-	17,328
BALANCE, DECEMBER 31, 2000................	$620,186	$5,386	$148,154	$565,132	$ (8,896)	$ (89,590)
Net earnings..............................	227,799	-	-	227,799	-	-
Minimum pension liability adjustment (net of income taxes of $1,306)........	(2,425)	-	-	-	(2,425)	-
Comprehensive income................	225,374					
Cash dividends (53 cents per share).......	(26,552)	-	-	(26,552)	-	-
Exercises of stock options................	24,011	-	7,310	-	-	16,701
BALANCE, DECEMBER 31, 2001................	$843,019	$5,386	$155,464	$766,379	$(11,321)	$ (72,889)

SHARE AMOUNTS	Common Stock Issued Class A	Common Stock Issued Class B	Treasury Stock Class A	Treasury Stock Class B	Total Shares Outstanding
BALANCE, DECEMBER 31, 1998	23,978,077	29,878,077	1,656,437	3,082,450	49,117,267
Other.....................................	(5)	(5)	-	-	(10)
BALANCE, DECEMBER 31, 1999	23,978,072	29,878,072	1,656,437	3,082,450	49,117,257
Treasury stock purchases..................	-	-	66,800	32,000	(98,800)
Exercises of stock options................	-	-	(610,118)	(167,642)	777,760
Other.....................................	(2)	(2)	-	-	(4)
Reclassification of common stock (Note 10).	29,878,070	(29,878,070)	2,946,808	(2,946,808)	-
BALANCE, DECEMBER 31, 2000	53,856,140	-	4,059,927	-	49,796,213
Exercises of stock options................	-		(756,808)		756,808
BALANCE, DECEMBER 31, 2001	53,856,140		3,303,119		50,553,021

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

Mitchell Energy & Development Corp. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(in thousands)

	2001	2000	1999
OPERATING ACTIVITIES			
Net earnings	$227,799	$ 257,146	$ 67,334
Adjustments to reconcile earnings to cash provided by operating activities			
Depreciation, depletion and amortization (including producing property impairment of $26,029 in 2001)	227,072	144,614	111,641
Exploratory well impairments	10,050	4,812	2,960
Deferred income taxes	99,731	54,045	19,552
Distributions in excess of earnings of equity investees	3,512	7,060	4,289
Louisiana Chalk asset impairment	-	10,762	-
Accrued personnel reduction program costs	-	-	17,620
Gains from dispositions of property, plant and equipment	(411)	(5,022)	(16,888)
Litigation provision reversals	-	(1,200)	(14,000)
Other, net	6,896	(5,989)	(2,888)
	574,649	466,228	189,620
Changes in operating assets and liabilities			
Trade receivables	109,713	(179,038)	13,012
Inventories	2,165	(11,309)	9,328
Federal income taxes receivable	(41,434)	-	4,294
Payables	(68,590)	97,180	10,421
Accrued liabilities and other	(8,591)	19,193	11,227
Cash provided by operating activities	567,912	392,254	237,902
INVESTING ACTIVITIES			
Capital expenditures	(687,218)	(302,434)	(158,408)
Proceeds from disposition of property, plant and equipment	1,408	17,123	44,220
Other, net	(5,117)	(3,015)	3,710
Cash used for investing activities	(690,927)	(288,326)	(110,478)
FINANCING ACTIVITIES			
Proceeds from issuance of debt	152,200	-	6,500
Debt repayments	(26,567)	(78,925)	(100,000)
Cash dividends (including special dividends of $12,311 in 2000)	(26,454)	(37,840)	(24,916)
Proceeds from stock option exercises	15,603	15,032	-
Treasury stock purchases	-	(2,768)	-
Other, net	-	-	(317)
Cash provided by (used for) financing activities	114,782	(104,501)	(118,733)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(8,233)	(573)	8,691
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	23,451	24,024	15,333
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 15,218	$ 23,451	$ 24,024

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of operations and principles of consolidation. Mitchell Energy & Development Corp. and its majority-owned subsidiaries (the "Company") constitute a large independent energy company engaged in the exploration for and development and production of natural gas, natural gas liquids, and crude oil and condensate. The Company also operates natural gas processing plants and gathering systems in Texas and markets the natural gas liquids extracted by its plants and the natural gas throughput of its gathering systems. The Company was acquired by Devon Energy Corporation in January 2002 (see Note 13).

The consolidated financial statements include the accounts of the Company after the elimination of intercompany accounts and transactions. The equity method of accounting is used for investments in 20%-to-50%-owned entities (see Note 3).

Use of estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue recognition. Natural gas, crude oil and condensate, natural gas liquids and gas gathering and marketing revenues are recorded on the sales method at the time products are sold or services are provided to third parties. Revenues and expenses attributable to the Company's NGL purchase and processing contracts are reported on a gross basis since it takes title to the products and has the risks and rewards of ownership and its compensation in such transactions is not on a commission or fee basis. The Company's revenue recognition practices are consistent with the provisions of Staff Accounting Bulletin No. 101 issued by the Securities and Exchange Commission in December 1999.

Property, plant and equipment. The Company's exploration and production activities are accounted for using the "successful efforts" method. Lease acquisition costs are capitalized as are costs to drill and equip development wells, including unsuccessful ones. Exploratory drilling costs are initially capitalized; if proved reserves are not found, such costs are subsequently impaired. Because of the nature of its drilling, the Company historically has made such determinations within one year. Geological and geophysical costs and other exploration costs are charged to expense as incurred. Depreciation, depletion and amortization (DD&A) of proved oil and gas properties is determined on a field-by-field basis using physical units of production. Estimated future costs of dismantlement, restoration and abandonment are considered in determining DD&A expense.

The Company holds no unproved leases whose costs are individually significant. Costs of unproved leaseholds are charged to expense based on historical holding periods and success rates. Leasehold costs for properties determined to be productive are transferred to proved oil and gas properties.

Other property, plant and equipment additions are recorded at cost and depreciated on the straight-line method over their estimated service lives, which range from 3 to 25 years. Maintenance and repair costs are charged to expense; costs of renewals and betterments are capitalized.

Long-lived assets held and used by the Company are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. When it is determined that an asset's estimated future net cash flows will not be sufficient to recover its carrying amount, an impairment charge is recorded to reduce the carrying amount for that asset to its estimated fair value. Impairment assessments for proved oil and gas properties are made on a field-by-field basis. Charges for such impairments, which are included in DD&A expense, totaled $26,029,000 in 2001 (see Note 9). Gas services asset impairments of $10,762,000 were recorded in 2000 (see Note 9).

Environmental expenditures. Liabilities for environmental expenditures are recognized when it is probable that obligations have been incurred in amounts that are material and reasonably estimable.

Statements of Cash Flows. Short-term investments with maturities of three months or less are considered to be cash equivalents. The reported amounts for proceeds from issuance of debt and debt repayments exclude the impact of borrowings with initial terms of three months or less. Excluding amounts capitalized of $7,534,000; $2,948,000 and $2,029,000, respectively, interest paid totaled $15,504,000; $26,242,000 and $35,182,000 during 2001, 2000 and 1999. Income taxes paid during those periods totaled $51,834,000; $53,143,000 and $5,591,000. Other than the asset exchange discussed in Note 3, there were no significant non-cash investing or financing activities during the three-year period ended December 31, 2001.

Reclassification. Certain reclassifications of amounts previously reported have been made to conform to current year reporting.

New accounting standards. The Financial Accounting Standards Board issued Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" in June 2001. This statement, which is effective for fiscal years beginning after June 15, 2002, generally requires the fair value of an asset retirement obligation to be recognized when an asset is placed in service.

In August 2001, the Financial Accounting Standards Board issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets", which is effective for fiscal years beginning after December 15, 2001. This statement establishes a uniform accounting methodology for long-lived assets to be disposed of by sale.

The Company's analyses of the impact of these new accounting standards has not been completed; consequently it is unable to project the effect, if any, their adoption will have on its financial statements.

(2) PROPERTY, PLANT AND EQUIPMENT

The cost and net book value of property, plant and equipment consisted of the following at December 31, 2001 and 2000 (in thousands):

	Cost		Net Book Value	
	2001	2000	2001	2000
EXPLORATION AND PRODUCTION				
Oil and gas properties..................	$2,482,996	$2,034,469	$1,083,846	$ 795,682
Support equipment and facilities.........	56,313	52,632	13,574	12,874
	2,539,309	2,087,101	1,097,420	808,556
GAS SERVICES (including investments in equity partnerships - Note 3)				
Natural gas processing..................	283,900	218,583	174,761	117,975
Natural gas gathering...................	491,783	357,038	300,622	190,569
Other..................................	83,925	86,771	83,124	86,077
	859,608	662,392	558,507	394,621
CORPORATE	17,056	15,939	2,685	2,828
	$3,415,973	$2,765,432	$1,658,612	$1,206,005

(3) UNCONSOLIDATED PARTNERSHIP INVESTMENTS

A summary of the Company's investments in partnerships at December 31, 2001 and 2000 and its equity in their pretax earnings for the years ended December 31, 2001, 2000 and 1999 follows (in thousands):

	Percent Owned	Investment		Equity in Pretax Earnings		
		2001	2000	2001	2000	1999
NATURAL GAS PROCESSING						
C&L Processors Partnership (C&L)...........	50(a)	$ -	$ -	$ -	$ 740	$ 4,596
U.P. Bryan Plant..........................	45(a)	-	-	-	4,640	7,419
		-	-	-	5,380	12,015
GAS GATHERING AND MARKETING						
Austin Chalk Natural Gas Marketing Services (Austin Chalk).......	45(a)	-	-	-	3	899
Ferguson-Burleson County Gas Gathering System (Ferguson-Burleson)....	45(a)	-	-	-	110	5,223
Louisiana Chalk Gathering System...........	50	3,874	4,217	(343)	(11,770)(b)	(908)
Others....................................		329	408	(79)	139	84
		4,203	4,625	(422)	(11,518)	5,298
OTHER						
Belvieu Environmental Fuels (BEF)..........	33.33	54,426	56,254	5,935	10,438	9,293
Gulf Coast Fractionators..................	38.75	27,357	28,375	2,373	2,641	3,357
		81,783	84,629	8,308	13,079	12,650
		$ 85,986	$89,254	$7,886	$ 6,941	$ 29,963

(a) Prior to the asset exchange on March 31, 2000.
(b) Includes an asset impairment charge of $10,762 (see Note 9).

For the applicable periods, the Company's net investment in each of these entities is reported as property, plant and equipment in the consolidated balance sheets and its equity in their pretax earnings is reported as revenues in the consolidated statements of earnings, each under the gas services caption.

During August 1999, C&L distributed the Jameson gas processing plant and related facilities to its partners, Conoco and a wholly-owned subsidiary of the Company. Effective October 1, 1999, the Jameson facilities became wholly owned when the Company purchased Conoco's 50% interest for approximately $23,900,000. As a result, these operations were consolidated and ceased being reported as part of C&L thus reducing C&L's operations to facilities located in Oklahoma.

On March 31, 2000, the Company exchanged its share of the gathering and processing assets of C&L (non-operated Oklahoma facilities having a net book value of $26,946,000) for Duke Energy Field Services, Inc.'s share of the Company operated gathering and processing assets of the U.P. Bryan Plant, Austin Chalk and Ferguson-Burleson partnerships and $11,666,000 in cash. Each of the four partnerships distributed all of their operating assets to their partners prior to the exchange and ceased operations. A gain of $4,884,000 was recognized in connection with the exchange. The results of the UP Bryan Plant, Austin Chalk and Ferguson-Burleson partnerships began being reported in the Company's consolidated results effective April 1, 2000.

Summarized balance sheet information (on a 100% basis) for the partnerships in which the Company held interests at December 31, 2001 and 2000 follows (in thousands):

	2001	2000
Current assets	$ 39,198	$ 45,234
Net noncurrent assets	223,616	238,546
Current liabilities	21,997	31,913
Owners' equity	240,817	251,867

For the applicable periods during which the Company held interests in the above-listed partnerships, summarized earnings information (on a 100% basis) for those partnerships for the years ended December 31, 2001, 2000 and 1999 follows (in thousands):

	2001	2000	1999
Revenues	$252,234	$382,421	$594,795
Operating earnings	21,252	25,685*	70,805
Pretax earnings	22,488	26,556*	61,542

* Reduced by an asset impairment charge of $21,524 on the Louisiana Chalk gathering system.

BEF owns a plant located at Mont Belvieu, Texas with the capacity to produce up to 17,000 barrels per day of MTBE, a gasoline additive that reduces emissions. BEF has entered into agreements which require each of the three partners to provide one-third of the plant's isobutane feedstock and one of the partners, Sun Company, Inc., to purchase all of its production for a period extending through September 2004.

Various state and federal government legislation requires or proposes to require that the use of MTBE be phased out. The earliest of these, for which a deferral is presently being contemplated, would ban the use of MTBE in California beginning in 2003. While the ultimate timing of any such bans is uncertain, restrictions on the use of MTBE would significantly impact future operations of the MTBE plant partially owned by the Company. However, that facility, which was built in the mid 1990s for approximately $225,000,000, was originally designed in a manner that allows it to be converted to the production of other products. It is not possible at this time to determine the ultimate impact, if any, of this matter on the Company's financial position or results of future operations.

(4) LONG-TERM DEBT

The Company's outstanding debt consists of unsecured parent company senior notes, the proceeds of which have been advanced to the operating subsidiaries, and borrowings under bank revolving credit and money market facilities. A summary of outstanding debt at December 31, 2001 and 2000 follows (in thousands):

	2001	2000
Unsecured senior notes		
9 1/4%, subsequently repaid on January 15, 2002	$ 62,920	$ 64,267
6 3/4%, due February 15, 2004	210,855	236,075
$250 million committed bank revolving credit agreement, unsecured	150,000	-
Uncommitted money market facilities, at floating interest rates	2,200	-
	425,975	300,342
Less - Current maturities	62,920	-
	$363,055	$300,342

The senior notes have no sinking fund requirements and are not redeemable prior to their respective maturity dates. During August 2000, the Company purchased $13,925,000 principal amount of the 6 3/4% senior notes at a small discount in the open market. Borrowings under the Company's $250,000,000 committed bank revolving credit facility (that was scheduled to terminate in July 2003) were repaid in January 2002 in connection with Devon's acquisition of the Company as were money market facility borrowings. Each of those agreements was then canceled.

The bank revolving credit agreement contained certain restrictions which, among other things, limited the payment of dividends by requiring consolidated tangible net worth, as defined, to equal at least $275,000,000 and require the maintenance of a specified consolidated leverage ratio based on earnings before interest, taxes and DD&A and excluding extraordinary, unusual, non-recurring and non-cash charges and credits. Retained earnings available for the payment of cash dividends totaled $567,244,000 at December 31, 2001. The indenture for the 6 3/4% senior notes limits the incurrence of liens on assets, properties or systems, restricts the sale or lease of certain assets and limits the right of the parent company and certain subsidiaries to merge with other companies. In connection with the acquisition by Devon, a subsidiary of Devon assumed the Company's obligations under the indenture.

(5) INCOME TAXES

Income taxes for the years ended December 31, 2001, 2000 and 1999 consisted of the following (in thousands):

	2001	2000	1999
CURRENT - Federal	$ 11,318	$ 59,235	$14,782
Prior years' Section 29 tax credits	-	(12,830)	-
State	90	361	330
	11,408	46,766	15,112
DEFERRED - Federal	101,880	60,100	18,309
State	(2,149)	238	1,243
Reversals of prior years' state taxes (net of deferred Federal impact of $3,388 in 2000)	-	(6,293)	-
	99,731	54,045	19,552
	$ 111,139	$ 100,811	$34,664

During 2000, the Company recorded $12,830,000 of prior years' Section 29 tax credits applicable to the Boonsville Bend Conglomerate field in North Texas. The credits were applicable to that field's production for the period February 1, 1992 through December 31, 1999. The Company recognized these credits when the Federal Energy Regulatory Commission once again began accepting requests for tight formation gas determinations on October 1, 2000, a certification process that it had discontinued in the early 1990s.

The prior-year state tax reversal of $6,293,000 in 2000 related to a legal reorganization of the Company's exploration and production operations, which allowed certain previously provided deferred state income taxes to be reversed.

Reconciliations between the 35% statutory Federal income tax rate and the Company's effective rates for income tax provisions (benefits) for 2001, 2000 and 1999 follow:

	2001	2000	1999
Statutory Federal income tax rate	35.0%	35.0%	35.0%
State income taxes, net of Federal income tax effect	(.4)	.1	1.0
Federal tax credits under Section 29 of the Internal Revenue Code for natural gas produced from certain wells	(1.9)	(1.5)	(2.7)
Other, net	.1	-	.7
	32.8	33.6	34.0
Prior years' Section 29 tax credits	-	(3.6)	-
Reversals of prior years' state taxes	-	(1.8)	-
	32.8%	28.2%	34.0%

The tax credit provisions under Section 29 are scheduled to expire at the end of 2002, and it is expected that the amount of the Company's credits for 2002 will not differ significantly from those applicable to 2001.

The principal components of the Company's deferred income tax liability consisted of the following at December 31, 2001 and 2000 (in thousands):

	2001	2000
Oil and gas acquisition, exploration and development costs deducted for tax purposes in excess of financial statement DD&A	$266,265	$181,730
Depreciation of other property, plant and equipment	60,907	48,917
Accrued compensation and benefits expenses not yet deductible for tax purposes	(35,848)	(36,461)
Unused alternative minimum tax credits	(2,424)	-
Other, net	7,850	9,733
	$296,750	$203,919

At December 31, 2001, the Company had $2,424,000 of unused alternative minimum tax credits that can be carried forward indefinitely. These credits have been recognized in the calculation of the Company's financial statement income tax provisions. Accordingly, their future utilization would only reduce the amount of taxes currently payable, not the financial statement income tax provision.

(6) COMMITMENTS AND CONTINGENCIES

Claims and legal actions. The Company is party to claims and legal actions arising in the ordinary course of its business and to recurring examinations performed by the Internal Revenue Service and other regulatory agencies. While the outcome of such matters cannot be predicted with certainty, management expects that losses, if any, resulting from their ultimate resolution will not result in charges that are material to the Company's financial position. It is possible, however, that charges could be required that would be significant to the operating results of a particular period.

Leases and contingent liabilities. The Company has various noncancellable equipment and facility operating lease agreements which provide for aggregate future payments of approximately $27,300,000. Minimum rentals for each of the five years subsequent to 2001 total approximately $10,500,000; $10,000,000; $5,900,000; $600,000 and $100,000. Rental expense for operating leases totaled approximately $10,400,000; $12,600,000 and $10,800,000 in 2001, 2000 and 1999. In addition to obligations described elsewhere in these notes, the Company had a contingent liability of $8,300,000 at December 31, 2001, consisting of a guarantee of third-party debt.

Environmental regulations. The Company is considered by the EPA to be a potentially responsible party with respect to two Superfund waste disposal sites. The only site involving more than minimal potential exposure to the Company is the Operating Industries, Inc. site located in Monterey Park, California, where small amounts of non-toxic drilling fluids were deposited from Company-operated oil and gas wells. Although the Company believes that it should be exempt from liability with respect to this site, through December 31, 2001 it had paid and expensed approximately $662,000 of costs. While additional exposure exists for future cleanup and closure costs of this site, the Company's share of such costs is not expected to be significant.

The Company continually monitors the many Federal, state and local laws and regulations relating to the protection of the environment and public health and believes it is in substantial compliance with such rules.

(7) FINANCIAL INSTRUMENTS

The carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2001 and 2000 were as follows (in thousands):

	2001		2000	
	Carrying Amounts	Estimated Fair Values	Carrying Amounts	Estimated Fair Values
Long-term debt..	$425,975	$430,644	$300,342	$299,441

Fair values of the Company's fixed-rate senior notes are based on quoted market prices. For floating-rate debt, carrying amounts and fair values are assumed to be equal because of the nature of these obligations. The carrying amounts of other on-balance-sheet financial instruments approximate their fair values. The aggregate cost to terminate off-balance-sheet financial instruments is not significant.

The Company does not hold or issue derivative financial instruments for trading purposes, and it had no open hedge positions at December 31, 2001 or 2000. As a result, the Company's adoption effective January 1, 2001 of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," had no significant impact on its financial statements.

(8) RETIREMENT BENEFITS

Substantially all full-time employees of the Company who meet specified age and service requirements are covered by a defined benefit retirement plan which is maintained without cost to the employees. Pension benefits are based on years of service and average earnings for the three highest consecutive years during the ten years immediately preceding retirement. The Company's funding policy is to make contributions to the plan of at least the minimum amounts required by applicable Federal laws and regulations; no such contributions were made in 2001, 2000 and 1999.

Internal Revenue Service regulations limit the benefits that may be paid to certain employees under the Company's qualified retirement plan. Nonqualified plans are maintained to make the basis on which those individuals' retirement benefits are determined the same as is used for other employees. A Rabbi trust fund is maintained from which these benefits are paid. That fund's assets - which under accounting principles generally accepted in the United States must be reported as an asset of the Company rather than being offset against the accrued benefit costs - totaled $23,231,000 and $22,503,000 at December 31, 2001 and 2000. These assets are included in Long-term Investments and Other Assets in the accompanying balance sheets. In connection with Devon's acquisition of the Company, contributions totaling $13,700,000 were made to the trust in January 2002 using funds advanced by Devon to bring that fund's assets in line with the estimated projected benefit obligation for nonqualified retirement benefits.

Retirees who reach retirement age while working for the Company and meet certain other eligibility requirements may elect coverage under the Company's postretirement medical benefits plan. This plan incorporates a scheduled-reimbursements methodology under which the Company and providers agree to specified rates for individual services. The Company has the right to amend or terminate medical benefits for active employees and retirees or to change the required level of participant contributions. The cost of providing these postretirement health care benefits is reduced by available Medicare coverage and retiree contributions. The plan is unfunded, and benefits are paid as costs are incurred.

The following table provides the indicated information for the years ended December 31, 2001 and 2000 concerning the Company's retirement plans and its postretirement medical benefits plan (amounts in thousands):

	Qualified Retirement Plan		Nonqualified Retirement Plans		Retiree Medical Benefits Plan	
	2001	2000	2001	2000	2001	2000
CHANGE IN BENEFIT OBLIGATION						
Benefit obligation, beginning of year	$161,229	$149,815	$24,404	$18,451	$41,724	$29,957
Service cost	2,982	3,033	182	365	938	517
Interest cost	11,938	11,219	1,787	1,368	3,115	2,233
Benefits paid	(10,045)	(10,259)	(1,978)	(1,562)	(2,613)	(2,804)
Actuarial losses	9,116	7,421	4,379	5,782	1,436	2,250
Plan amendments	298	-	(298)	-	-	9,171
Contributions by plan participants	-	-	-	-	691	400
Benefit obligation, end of year	$175,518	$161,229	$28,476	$24,404	$45,291	$41,724
CHANGE IN PLAN ASSETS						
Plan assets at fair value, beginning of year	$171,783	$182,534				
Actual return on plan assets	(14,090)	(492)				
Benefits paid	(10,045)	(10,259)				
Plan assets at fair value, end of year	$147,648	$171,783				
FUNDED STATUS AT YEAR END						
Plan assets over (under) benefit obligation	$(27,870)	$ 10,554	$(28,476)	$(24,404)	$(45,291)	$(41,724)
Unrecognized (gains) losses	7,841	(31,621)	17,932	14,604	10,536	9,438
Unrecognized prior service cost	753	509	(222)	100	4,188	3,985
Unrecognized net transition obligation	-	-	-	7	-	-
Minimum pension liability adjustment	-	-	(17,417)	(13,793)	-	-
Accrued balance sheet liability	$(19,276)	$(20,558)	$(28,183)	$(23,486)	$(30,567)	$(28,301)
MINIMUM PENSION LIABILITY ADJUSTMENT						
Additional minimum liability			$ 17,417	$ 13,793		
Offsetting intangible asset			-	107		
			$ 17,417	$ 13,686		

The actuarial assumptions used in computing the amounts disclosed herein included discount rates of 7.15%, 7.50% and 7.75% in 2001, 2000 and 1999, an expected annual rate of return on plan assets of 9% and age-graded annual salary increases ranging from 3.5% to 5.5%.

Components of financial statement expense for the Company's retirement plans and its retiree medical benefits plan for the years ended December 31, 2001, 2000 and 1999 were (in thousands):

	2001	2000	1999
QUALIFIED RETIREMENT PLAN			
Service cost	$ 2,982	$ 3,033	$ 3,269
Interest cost	11,938	11,219	11,050
Return on plan assets (expected)	(15,009)	(15,973)	(14,889)
Amortization of prior service cost	55	127	80
Amortization of unrecognized gains	(1,248)	(3,474)	(1,350)
Net periodic benefit cost (credit)	(1,282)	(5,068)	(1,840)
Charges for curtailments and special termination benefits.	-	-	12,687*
Financial statement expense (credit)	$(1,282)	$ (5,068)	$10,847
NONQUALIFIED RETIREMENT PLANS			
Service cost	$ 183	$ 365	$ 359
Interest cost	1,787	1,368	1,322
Amortization of prior service cost/transition obligation..	31	107	225
Amortization of unrecognized losses	1,051	653	837
Net periodic benefit cost	3,052	2,493	2,743
Charges for curtailments and special termination benefits.	-	-	827*
Financial statement expense	$ 3,052	$ 2,493	$ 3,570
RETIREE MEDICAL PLAN			
Service cost	$ 938	$ 517	$ 622
Interest cost	3,115	2,233	1,875
Amortization of prior service cost credit	(203)	(791)	(791)
Amortization of unrecognized losses	338	291	298
Net periodic benefit cost	4,188	2,250	2,004
Charges for curtailments and special termination benefits.	-	-	4,106*
Financial statement expense	$ 4,188	$ 2,250	$ 6,110

* These charges - which totaled $17,620 - were related to a personnel reduction program (see Note 9).

The Company's assumed health care cost trend rate equals 8% for 2002, declines 1% each year to 2005 and remains at 5% thereafter. The health care cost trend rate assumption has a significant effect on the amount of the retiree medical benefit obligation and the periodic financial statement expense. An increase of 1% in the assumed trend rate would have increased the retiree medical benefit obligation at December 31, 2001 by $6,091,000 and the service and interest cost components of the 2001 financial statement expense by a total of $717,000. A decrease of 1% in the trend rate would have reduced these amounts by $5,073,000 and $537,000, respectively.

The Company maintains a defined contribution plan in which eligible employees may participate on a voluntary basis. The Company's contributions - which match each employee's contributions on a dollar-for-dollar basis up to 6% of eligible compensation - totaled $2,536,000; $2,460,000 and $2,617,000 in 2001, 2000 and 1999.

(9) SEGMENT INFORMATION

Selected industry segment data for the years ended December 31, 2001, 2000 and 1999 follows (in thousands):

	Outside Revenues	Inter-segment Revenues	Segment Operating Earnings	Total Operating Earnings	DD&A	Capital Expendi-tures(a)	Segment Assets
2001							
EXPLORATION AND PRODUCTION							
Operations	$ 656,404	$ --	$ 339,651	$ 329,282	$ 165,371	$ 491,865	$1,113,125
Proved property impairment	--	--	(26,029)	(26,029)	26,029	--	--
	656,404	--	313,622	303,253	191,400	491,865	1,113,125
GAS SERVICES							
Natural gas processing	607,747	304,072	35,789	32,306	9,266	67,983	213,748
Natural gas gathering and marketing	546,477	790,873	31,378	27,441	24,945	136,099	376,970
Other	8,308	--	7,624	7,300	107	244	83,302
	1,162,532	1,094,945	74,791	67,047	34,318	204,326	674,020
CORPORATE	--	--	--	(14,618)(b)	1,354	2,038	124,293
	$1,818,936	$1,094,945	$ 388,413	$ 355,682	$ 227,072	$ 698,229	$1,911,438
2000							
EXPLORATION AND PRODUCTION							
Operations	$ 531,213	$ --	$ 290,385	$ 281,110	$ 118,112	$ 237,811	$ 913,094
Water well litigation provision reversal	--	--	1,200	1,200	--	--	--
	531,213	--	291,585	282,310	118,112	237,811	913,094
GAS SERVICES							
Natural gas processing	668,321	232,405	84,516	81,439	6,306	46,526	176,639
Natural gas gathering and marketing	454,489	616,026	41,863	38,370	18,454	51.844	272,819
Other	13,089	--	12,338	12,076	107	1,780	86,306
Louisiana Chalk asset impairment	--	--	(10,762)	(10,762)	--	--	--
	1,135,899	848,431	127,955	121,123	24,867	100,150	535,764
CORPORATE	--	--	--	(27,632)(b)	1,635	1,102	70,907
	$1,667,112	$ 848,431	$ 419,540	$ 375,801	$ 144,614	$ 339,063	$1,519,765
1999							
EXPLORATION AND PRODUCTION							
Operations	$ 254,009	$ --	$ 70,671	$ 60,538	$ 94,667	$ 112,352	$ 717,787
Water well litigation provision reversals	--	--	14,000	14,000	--	--	--
Personnel reduction program costs	--	--	(8,524)	(8,524)	--	--	--
	254,009	--	76,147	66,014	94,667	112,352	717,787
GAS SERVICES							
Natural gas processing	384,587	83,664	47,161	44,293	4,070	23,871	115,300
Natural gas gathering and marketing	226,371	263,874	23,173	19,917	10,341	21,067	156,141
Other	12,501	--	11,720	11,389	107	199	86,323
Personnel reduction program costs	--	--	(7,128)(c)	(7,128)	--	--	--
	623,459	347,538	74,926	68,471	14,518	45,137	357,764
CORPORATE	--	--	--	(21,038)(b)	2,456	480	88,128
	$ 877,468	$ 347,538	$ 151,073	$ 113,447	$ 111,641	$ 157,969	$1,163,679

(a) On accrual basis.
(b) General corporate expenses; 1999 amount includes personnel reduction program costs of $8,848.
(c) Natural gas processing $1,753; natural gas gathering and marketing $5,375.

The Company's reported business segments are based on the organizational structure used by management to assess performance and make resource allocation decisions. The Company's three principal business segments are: exploration and production, natural gas processing, and natural gas gathering and marketing. Exploration and production segment operations include the exploration for and development and production of natural gas and oil. Natural gas processing segment operations include the extraction of natural gas liquids from natural gas processed at facilities owned by the Company and third parties. The gas gathering and marketing segment operates Company-owned natural gas gathering systems and markets natural gas through purchase and resale transactions.

All of the Company's operations are conducted in the United States. Its revenues are derived principally from uncollateralized sales to customers in the electrical generation, gas distribution, petrochemical and oil and gas industries. These industry concentrations have the potential to impact the Company's exposure to credit risk, either positively or negatively, because customers may be similarly affected by changes in economic or other conditions.

Intersegment revenues are recorded at prevailing market prices and are eliminated in consolidation. Gas gathering and marketing sales to a single customer constituted approximately 21% and 14% of consolidated revenues during 2001 and 2000. Sales to no single customer constituted as much as 10% of consolidated revenues in 1999.

The reported segment operating earnings amounts represent the operating earnings of the Company's various industry segments before charges for administrative, accounting, legal, information systems and other costs that are managed on a companywide basis. In the reported total operating earnings disclosures, all general and administrative expenses except for general corporate expenses incurred in connection with the overall management of the Company and the operation of the parent company have been allocated to the industry segments based on their estimated use of these services.

Because of their magnitude and unusual nature, and in accordance with Accounting Principles Board Opinion No. 30, the items discussed in the following paragraphs have been reported as separate components of segment operating earnings.

During September 2001, the Company recorded an impairment charge of $26,029,000 to reduce the carrying value of a gas field to its estimated fair value (the present value of its estimated future net cash flows). The impairment was the result of less than successful drilling results since the affected property was acquired in 1998 and sharp declines in forecasted natural gas prices during the third quarter of 2001.

As a result of entering into agreements with insurance carriers reimbursing the Company for defense costs incurred in connection with previously resolved litigation, water well litigation provision reversals of $1,200,000 and $14,000,000, respectively, were recorded in 2000 and 1999.

During December 2000, the Company recorded a $10,762,000 impairment charge to reduce the carrying value of the 50%-owned Louisiana Chalk pipeline system. Drilling activity around the system, which had been expected to resume when industry conditions improved, did not materialize during 2000.

During the first quarter of 1999, the Company completed a personnel reduction program which reduced its full-time employment level by 235 jobs. Aggregate pretax costs of this program - including $8,848,000 reported as general and administrative expense - totaled $24,500,000. Of these costs, $17,620,000 represented the present value of incremental pension and retiree medical benefits provided under a voluntary incentive retirement program offered to 127 employees (114 of whom accepted). Cash costs of severance and other benefits totaled $6,880,000. The majority of the cash costs were paid by March 31, 1999, and no accrued liability for such costs remained at December 31, 1999.

(10) COMMON STOCK AND STOCK OPTIONS

In June 2000, the Company's stockholders voted to combine its two classes of common stock into a single class of voting common stock by reclassifying each share of Class B common stock into one share of Class A common stock. Also, the number of authorized shares of Class A common stock was increased from 100,000,000 to 200,000,000.

The Company's 1995 and 1999 Stock Option Plans authorized the granting of incentive and nonqualified options to purchase common stock at prices not less than the market value on the date of grant. The options have maximum terms of 10 years and become exercisable ratably over three-year periods. At December 31, 2001 (prior to closing of the Company's acquisition by Devon), grants covering an additional 1,074,621 shares could be issued under the plans, and the weighted average remaining contractual life of stock options outstanding under these plans was 7.53 years. Previously, options had been granted under the Company's 1979 and 1989 Stock Option Plans, under which no further grants can be made. Summarized stock option information follows:

	1995 and 1999 Plans				1979 and 1989 Plans			
	Options Outstanding		Options Exercisable at Year End		Options Outstanding		Options Exercisable at Year End	
	Number	Average Price	Number	Average Price	Number	Average Price	Number	Average Price
At December 31, 1998.......	1,608,488	20.93	911,607	19.72	151,670	19.93	111,670	19.75
March 15, 1999 grants......	405,400	12.31			-			
Exercised..................	-	-			(10,000)	17.25		
Canceled...................	(27,525)	19.71			-			
At December 31, 1999.......	1,986,363	19.19	1,331,294	20.45	141,670	20.12	141,670	20.12
May 1, 2000 grants.........	453,100	23.94			-			
Exercised..................	(668,490)	19.21			(109,270)	20.05		
Canceled...................	(9,368)	16.66			-			
At December 31, 2000.......	1,761,605	20.41	1,046,460	20.95	32,400	20.36	32,400	20.36
May 9, 2001 grants.........	459,750	54.00			-			
Exercised..................	(724,408)	20.63			(32,400)	20.36		
Canceled...................	(8,835)	25.81			-			
At December 31, 2001.......	1,488,112	30.65	602,794	20.18	-			

Stock options are accounted for under the provisions of APB Opinion No.
25. As a result, the Company does not recognize compensation expense in its financial statements for outstanding stock options. Had grants under the option plans been accounted for on the estimated fair-value basis promulgated by SFAS No. 123, the Company would have recorded additional compensation expense of $3,178,000; $1,947,000 and $2,159,000 in 2001, 2000 and 1999. On a proforma basis, earnings from continuing operations would have been reduced by $2,065,000; $1,266,000 and $1,404,000 in 2001, 2000 and 1999, and basic earnings per share from continuing operations would have been lowered by 4 cents, 3 cents and 3 cents, respectively. The additional compensation expense under the estimated fair-value basis was computed using the Black-Scholes option-pricing model, expected lives of seven years, annual cash dividends of $.53 per share (the regular rate paid for the last several years) and the following interest and volatility rates, which were determined at the dates of the individual grants:

	May 9, 2001	May 1, 2000	March 5, 1999
Risk-free interest rate (%)....................	5.20	6.40	5.34
Stock price volatility rate (%)...............	33.59	30.33	29.70
Computed value per option share...............	$22.73	$8.93	$3.17

(11) INCENTIVE COMPENSATION PLANS

As long-term incentives, the Company periodically issued awards that it calls "bonus units" under which employees can earn compensation based on increases in the market price of the Company's stock. Such awards generally were made in lieu of stock option grants. Upon the redemption of bonus units, grantees receive gross compensation in amounts equal to the excess of the market price of the Company's common stock over a floor price (the market price of the stock when the units were awarded). Up to 1,500,000 units may be granted under the 1997 Bonus Unit Plan. The bonus units generally have ten-year terms and vest in three equal annual installments. Bonus unit grants under the 1997 Plan were as follows: 227,950 in December 1997 at a floor price of $26.125; 249,600 in March 1999 at a floor price of $12.3125; 342,800 in May 2000 at a floor price of $23.9375 and 354,200 in May 2001 at a floor price of $54.00. At December 31, 2001, a total of 861,056 bonus units were outstanding with an average floor price of $35.1552. Of such units, 195,115 were exercisable at an average floor price of $23.8255.

Compensation expense is recognized over the applicable vesting terms of the bonus units in amounts equal to the appreciation in the market price of the stock over the applicable floor prices. Reversals are recognized to the extent of previously recorded appreciation in periods when the market price of the stock declines. Expense accruals for bonus units aggregated $2,192,130; $21,282,728 and $1,293,000 in 2001, 2000 and 1999.

(12) EARNINGS PER SHARE The following table reconciles the weighted average shares outstanding used in the basic and diluted earnings per share computations for the years ended December 31, 2001, 2000 and 1999 (in thousands):

	2001	2000	1999
Used in basic computations	50,000	49,291	49,117
Dilutive effect of stock options	889	793	106
Used in diluted computations	50,889	50,084	49,223

Excluded from these computations because their effect would have been antidilutive were stock options covering 458,350 shares in 2001 and 1,388,233 shares in 1999. No shares were so excluded in 2000.

(13) SUBSEQUENT EVENT

In a transaction closed on January 24, 2002, Devon Energy Corporation (Devon) acquired the Company for cash and stock. Shareholders of the Company received $31.00 cash and 0.585 of a share of Devon common stock for each of the Company's shares they owned. In connection with the transaction, balances then outstanding under the Company's committed bank revolving credit and uncommitted money market facilities were repaid using the proceeds of long-term loans from Devon. Also, all outstanding stock options and bonus units held by the Company's employees were vested and converted into options to purchase Devon's common stock and bonus units redeemable for cash based on the market price of Devon's common stock. The number of outstanding options and bonus units were multiplied by 1.20 and their exercise/floor prices were divided by 1.20 as part of the conversion.

(14) SALE OF OIL AND GAS PROPERTY

During June 1999, the Company sold for cash all its oil and gas properties in the Hell's Hole and Park Mountain fields in Colorado and Utah, which consisted of 24,000 net leasehold acres with 36 producing wells and associated pipelines, gathering systems and production facilities. A pretax gain of $11,527,000 ($7,190,000 after tax) was recognized on the sale.

Reserve quantities. Proved reserves are the estimated quantities which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under economic and operating conditions at each year end. Proved developed reserves are expected to be recovered from existing wells using existing equipment and operating methods.

Gas and oil reserves included in this Unaudited Supplemental Oil and Gas Information section are presented in compliance with Statement of Financial Accounting Standards No. 69 and represent oil and gas reserves derived from the Company's net mineral interest in producing oil and gas properties.

The amounts reported separately as Plant NGL Reserves represent NGLs that will be extracted from gas streams contractually committed to company-owned gas processing plants and are included in order to disclose important and useful information related to the gas processing segment. The NGL reserves represent all the NGLs that will be derived by processing natural gas produced from (i) oil and gas properties owned/operated by the Company and (ii) oil and gas properties operated by others whose gas production is tied into the gas processing facilities and contractually purchased, processed and sold by the Company.

The following tables summarize changes in the Company's natural gas (gas), crude oil and condensate (oil) and plant NGL reserve quantities during the indicated years and the proved developed reserve quantities at the dates indicated:

	2001			2000			1999		
	Bcfe *	Gas (Bcf)	Oil (MMBbls)	Bcfe *	Gas (Bcf)	Oil (MMBbls)	Bcfe *	Gas (Bcf)	Oil (MMBbls)
PROVED GAS AND OIL RESERVES									
Beginning balance	1,507.7	1,436.0	12.0	1,106.5	1,022.8	14.0	973.6	875.2	16.4
Extensions and discoveries	712.3	694.9	2.9	547.5	539.1	1.4	297.0	289.8	1.2
Production marketed	(162.8)	(150.8)	(2.0)	(123.8)	(111.8)	(2.0)	(101.9)	(89.3)	(2.1)
Production consumed in operations	(5.3)	(5.3)	--	(4.7)	(4.7)	--	(4.5)	(4.5)	--
Purchases in place	1.6	1.6	--	4.3	4.3	--	.1	.1	--
Revisions of previous estimates	(21.8)	(18.2)	(.6)	(18.2)	(11.6)	(1.1)	(48.0)	(39.9)	(1.3)
Sales in place	(.1)	(.1)	--	(3.9)	(2.1)	(.3)	(9.8)	(8.6)	(.2)
Ending balance	2,031.6	1,958.1	12.3	1,507.7	1,436.0	12.0	1,106.5	1,022.8	14.0

* Billion cubic feet of gas equivalent using a 6-to-1 conversion factor for oil.

	2001			2000			1999		
	Total	Consol-idated	Equity Partner-ships**	Total	Consol-idated	Equity Partner-ships**	Total	Consol-idated	Equity Partner-ships**
PROVED PLANT NGL RESERVES (MMBBLS)									
Beginning balance..................	175.0	175.0	-	179.1	148.8	30.3	115.8	75.9	39.9
Additions..........................	67.0	67.0	-	42.9	42.9	-	28.2	27.1	1.1
Production.........................	(19.8)	(19.8)	-	(18.2)	(17.5)	(.7)	(16.1)	(12.2)	(3.9)
Purchase (sale) of plant interests..	-	-	-	(6.2)	11.4	(17.6)	15.2	15.2	-
Transfer of partnership reserves....	-	-	-	-	12.1	(12.1)	-	15.2	(15.2)
Revisions of previous estimates.....	6.5	6.5	-	(22.6)	(22.7)	.1	36.0	27.6	8.4
Ending balance.....................	228.7	228.7	-	175.0	175.0	-	179.1	148.8	30.3

PROVED DEVELOPED RESERVES AT DECEMBER 31	2001	2000	1999	1998
Gas (Bcf)	953.7	737.0	667.1	692.3
Oil (MMBbls)......................................	10.2	11.4	13.5	15.2
Plant NGLs (MMBbls)				
Consolidated	134.3	115.2	119.3	58.7
Equity partnerships	-	-	24.4	33.3
	134.3	115.2	143.7	92.0

**Represent the Company's proportional interest in the reserves of partnerships accounted for using the equity method.

Future net cash flows from natural gas and oil reserves. The following tables set forth estimates of the standardized measure of discounted future net cash flows from proved gas and oil reserves at December 31, 2001, 2000 and 1999 and a summary of the changes in those amounts for the years then ended (in millions):

	2001	2000	1999
STANDARDIZED MEASURE			
Future cash inflows	$ 5,131	$ 12,945	$ 2,792
Future production costs	(1,740)	(1,993)	(1,207)
Future development costs	(951)	(564)	(248)
Future income taxes	(767)	(3,547)	(374)
Discount - 10% annually	(802)	(2,885)	(385)
	$ 871	$ 3,956	$ 578
CHANGES IN STANDARDIZED MEASURE			
Extensions and discoveries, net of related costs	$ 247	$ 2,105	$ 188
Sales, net of production costs	(580)	(439)	(184)
Net changes in prices and production costs	(5,121)	3,584	340
Accretion of discount	601	74	42
Production rate changes and other	(117)	(53)	(28)
Previously estimated development costs incurred	260	54	26
Purchases in place	2	20	-
Sales in place	-	(12)	(13)
Revisions of previous quantity estimates	(26)	(68)	(63)
Net changes in future income taxes	1,649	(1,887)	(122)
	$ (3,085)	$ 3,378	$ 186

Development costs for proved undeveloped reserves. The costs of drilling wells and other development projects whose previously recorded proved undeveloped reserves were transferred to proved developed during 2001, 2000 and 1999 totaled $314,788,000; $73,327,000 and $31,506,000, respectively. During the following three years, the Company estimates that such costs will total approximately $340,000,000; $414,000,000 and $161,000,000.

Future net cash flows from plant NGL reserves. The following tables set forth estimates of the standardized measure of discounted future net cash flows from proved plant NGL reserves at December 31, 2001, 2000 and 1999 and a summary of the changes in those amounts for the years then ended (in millions):

		2000			1999		
	2001	Total	Equity Consol-idated	Partner-ships	Total	Equity Consol-idated	Partner-ships
STANDARDIZED MEASURE							
Future cash inflows	$2,845	$5,533	$5,533	$ -	$2,976	$ 2,508	$ 468
Future production costs	(2,249)	(4,026)	(4,026)	-	(2,281)	(1,978)	(303)
Future income taxes	(167)	(505)	(505)	-	(228)	(168)	(60)
Discount - 10% annually	(176)	(430)	(430)	-	(202)	(153)	(49)
	$ 253	$ 572	$ 572	$ -	$ 265	$ 209	$ 56
CHANGES IN STANDARDIZED MEASURE							
Additions, net of related costs	$ 101	$ 210	$ 210	$ -	$ 57	$ 54	$ 3
Sales, net of production costs	(55)	(91)	(85)	(6)	139	83	56
Net changes in prices and costs	(658)	480	480	-	(45)	(30)	(15)
Accretion of discount	86	29	29	-	10	6	4
Purchase/sale of plant interests	-	(51)	(4)	(47)	30	30	-
Transfer of partnership reserves	-	-	37	(37)	-	30	(30)
Revisions of previous quantity estimates	10	(111)	(111)	-	80	55	25
Other	3	7	7	-	9	5	4
Net changes in future income taxes	194	(166)	(200)	34	(94)	(70)	(24)
	$ (319)	$ 307	$ 363	$ (56)	$ 186	$ 163	$ 23

The natural gas quantities reported as gas and oil reserves represent wet gas volumes, including quantities that will be converted to NGLs by processing. As it relates to NGLs to be extracted in processing, the gas and oil future net cash flows include only the leasehold reimbursements for such NGLs; the other cash flows (amounts in excess of the leasehold reimbursements) associated with NGLs to be extracted from the Company's wet gas reserves are included in plant NGL amounts since those cash flows are attributable to the Company's gas processing plants.

The future net cash flows from plant NGL reserves represent the net amounts to be derived from gas plant ownership through natural gas purchase and processing agreements. The Company's gas processing affiliate purchases raw natural gas production (including all the liquefiable hydrocarbons contained therein) from producers (both the Company's exploration and production affiliate and third parties) during the term of the purchase and processing agreements. The processing affiliate takes title to the wet gas (including the entrained NGLs) and then processes the gas for the extraction of the NGLs. Generally, under the purchase and processing agreements, the producer is paid for the NGLs associated with its gas under one of two methods. Under one method, reimbursements to the producer are based on the value of the reduction in the heating content (measured in BTUs) of the gas that is attributable to the removal of the NGLs from the gas. This method is sometimes referred to as a "Btu purchase contract" or a "keep whole contract". Under the other method, which is called a "percent of proceeds contract", the producer is paid based on a percentage of the value of NGLs extracted. Regardless of the payment method, settlements to producers are in cash, not product, and title to 100% of the NGLs is assigned to the gas processing affiliate, which bears the risks and rewards of ownership. Such reimbursements - including amounts attributable to the Company's oil and gas leasehold interests that are included in oil and gas future net cash flows - are deducted as production costs in determining future net cash flows from plant NGLs.

Under the gas purchase and processing agreements, the Company's gas processing affiliate is generally obligated to gather and compresses the gas from the point of delivery to a central processing plant, to hydrate the gas, and, if necessary, treat the gas for the removal of contaminants such as carbon dioxide and hydrogen sulfide and process the gas for the extraction of NGLs. After the NGLs are removed, the gas processing affiliate compresses the residue natural gas coming out of the plant and markets the residue gas. The NGLs extracted at the plant are a raw mixture of ethane, propane, isobutane, normal butane and natural gasoline which is then separated into individual purity products at an on-site fractionator or sent via a third-party-owned pipeline to a large central fractionator and then sold to wholesale and industrial customers.

Of the total remaining natural gas reserves at December 31, 2001, an estimated 1,172.1 Bcf will be processed at Company plants, including 398.1 Bcf of 2001's natural gas reserve additions from extensions and discoveries. It is estimated that 246.0 Bcf of such reserves and 86.5 Bcf of such reserve additions will be converted by processing into 104.9 MMBbls and 38.9 MMBbls of plant NGLs, respectively.

Because of the volatility inherent in prices for natural gas, oil and NGLs and costs to develop reserves, future cash flow estimates such as those included herein can change dramatically over even short periods of time. Future cash flows from plant NGL reserves can also be significantly impacted by changes in the spread between NGL prices and natural gas costs. Except where otherwise specified by contractual agreement, future cash inflows are estimated using year-end prices. Future production and development cost estimates are based on economic conditions at the respective year ends. Future income taxes are computed by applying applicable statutory tax rates to the difference between the estimated future net revenues and the tax basis of proved oil and gas properties after considering tax credit carryforwards, estimated future percentage depletion deductions and energy tax credits.

Reserve estimates are subject to numerous uncertainties inherent in estimating quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. Because of the aforementioned factors, reserve estimates are generally less precise than other financial statement disclosures.

Discounted future cash flow estimates such as those shown herein are not intended to represent estimates of the fair market value of oil and gas properties. Estimates of fair market value also should consider probable reserves, anticipated future oil and gas prices and interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair market value is necessarily subjective and imprecise.

Gas and oil related costs and operating results. The following tables set forth capitalized costs at December 31, 2001, 2000 and 1999 and costs incurred and operating results for oil and gas producing activities for the years then ended (in thousands):

	2001	2000	1999
CAPITALIZED COSTS			
Oil and gas properties	$ 2,482,996	$ 2,034,469	$ 1,881,846
Support equipment and facilities	56,313	52,632	50,138
Accumulated depreciation, depletion and amortization	(1,441,889)	(1,278,545)	(1,231,047)
Net capitalized costs	$ 1,097,420	$ 808,556	$ 700,937
COSTS INCURRED (including exploration expenses and exploratory well impairments of $18,611; $12,028 and $9,022)			
Property acquisitions			
Unproved	$ 20,085	$ 16,916	$ 6,450
Proved	5,931	1,565	-
Exploration	24,927	15,309	9,646
Development	445,949	208,510	101,589
Costs incurred	$ 496,892	$ 242,300	$ 117,685
OPERATING RESULTS (before charges for general and administrative and interest expense)			
Production revenues	$ 654,905	$ 530,085	$ 252,899
Other revenues	1,499	1,143	1,462
	656,404	531,228	254,361
Less - Production costs			
Operating expenses	76,613	62,316	52,044
Production taxes	41,659	28,520	16,371
Depreciation, depletion and amortization (including proved-property impairments of $26,029 in 2001)	191,400	118,112	94,667
Exploration expenses	8,561	7,216	6,062
Exploratory well impairments	10,050	4,812	2,960
Other operating costs	14,499	19,852	11,234
Segment operating earnings	313,622	290,400	71,023
Income taxes	101,266	77,032	23,009
	$ 212,356	$ 213,368	$ 48,014

UNAUDITED PRO FORMA COMBINED FINANCIAL INFORMATION

The following unaudited pro forma combined financial information relates to the merger between Devon and Mitchell, whereby on January 24, 2002, Devon acquired all of Mitchell's outstanding common shares with 0.585 shares of Devon common stock plus $31 per Mitchell common share in cash. The unaudited pro forma combined financial information also includes the effects of Devon's October 15, 2001 acquisition of Anderson Exploration Ltd. ("Anderson") for approximately $3.5 billion. The unaudited pro forma combined financial information includes a balance sheet as of December 31, 2001, which assumes the acquisition of Mitchell occurred on that date. The unaudited pro forma combined financial information also includes a statement of operations for the year ended December 31, 2001, which assumes the acquisitions of Mitchell and Anderson occurred on January 1, 2001.

This pro forma information is based on the historical financial statements of Devon, Mitchell and Anderson. The pro forma information is based on the estimates and assumptions set forth in the notes to such information. The pro forma information is being furnished solely for information purposes and, therefore, is not necessarily indicative of the results of operations or financial position that might have been achieved for the dates or periods indicated, nor is it necessarily indicative of the results of operations or financial position that may occur in the future.

Anderson's historical financial information is prepared in accordance with accounting standards generally accepted in Canada, and is presented in Canadian dollars. Also, Anderson's fiscal year ended on September 30, as opposed to Devon's year-end of December 31. For purposes of providing the pro forma effect of the Anderson acquisition on Devon's 2001 results of operations, the following adjustments were made to Anderson's historical financial data:

- Anderson's historical results for the year ended September 30, 2001 were converted to results for the nine months ended September 30, 2001. This conversion was done by subtracting Anderson's historical interim results for the three months ended December 31, 2000.

- Anderson's results of operations for the nine months ended September 30, 2001, were converted to accounting principles generally accepted in the United States, including the full cost method of accounting for oil and gas properties. Such information was also converted to U.S. dollars using the appropriate exchange rates.

The unaudited pro forma combined financial information was prepared based on the following:

- Devon uses the full cost method of accounting for its oil and gas activities, while Mitchell used the successful efforts method. Pro forma adjustments have been made to estimate the effect of converting Mitchell's successful efforts method to Devon's full cost method.

- Devon has accounted for the merger and the Anderson acquisition using the purchase method of accounting.

- The unaudited pro forma balance sheet has been prepared as if the merger occurred on December 31, 2001. The unaudited pro forma statement of operations has been prepared as if the merger and the Anderson acquisition occurred on January 1, 2001.

- In the year ended December 31, 2001, Devon recognized a $49.5 million after-tax gain from the cumulative effect of a change in accounting principle. This related to Devon's adoption, as of January 1, 2001, of a new accounting principle related to accounting for derivative financial instruments. The $49.5 million gain is not included in the unaudited pro forma combined statements of operations for the nine months ended September 30, 2001.

- There is no adjustment to the historical data for annual cost savings of approximately $20 million and $25 million that Devon expects to result from the elimination of duplicate expenses after the merger and the Anderson acquisition, respectively.

No pro forma adjustments have been made with respect to the following unusual items. These items are reflected in the historical results of Devon, Anderson or Mitchell, as applicable, and should be considered when making period-to-period comparisons:

- On February 12, 2001, Anderson acquired all of the outstanding shares of Numac Energy Inc. The unaudited pro forma combined statement of operations does not include any results from Numac's operations prior to February 12, 2001.

- During 2001, Devon elected to discontinue operations in Malaysia, Qatar, Thailand and on certain properties in Brazil. Accordingly, during 2001, Devon recorded an $87.9 million charge associated with the impairment of those properties. The after-tax effect of this reduction was $68.8 million.

- During 2001, Devon reduced the carrying value of its oil and gas properties by $915.7 million due to the full cost ceiling limitations. The after-tax effect of this reduction was $556.5 million.

- Anderson had a compensation plan pursuant to which it periodically issued awards referred to as "share appreciation rights" under which employees could earn compensation based on increases in the market price of Anderson's stock. Anderson awarded these rights in lieu of stock option grants. Pro forma general and administrative expenses reported in the accompanying unaudited pro forma statement of operations for the year ended December 31, 2001 includes $5.6 million of expenses related to these plans. After taxes, these plans had the effect of decreasing unaudited pro forma net earnings in 2001 by $3.2 million. Devon acquired all outstanding rights as part of the Anderson acquisition. Accordingly, these rights will not affect the combined company's net earnings subsequent to the closing of the Anderson acquisition.

- Mitchell had incentive compensation plans pursuant to which it periodically issued awards referred to as "bonus units" under which employees could earn compensation based on increases in the market price of Mitchell common stock. Mitchell generally awarded these bonus units in lieu of stock option grants. Pro forma general and administrative expenses reported in the accompanying unaudited pro forma statements of operations for the year 2001 include $2.2 million of expense related to these plans. After taxes, these plans had the effect of decreasing unaudited pro forma net earnings in 2001 by $1.4 million. Devon will not issue such bonus units after the merger.

- Devon's historical results of operations for the year 2001 include $33.8 million of amortization expense for goodwill related to previous mergers. As of January 1, 2002, in accordance with new accounting pronouncements recently issued, such goodwill will cease to be amortized and, instead, will be tested for impairment at least annually. No goodwill amortization expense has been recognized in the pro forma statements of operations for the goodwill related to the merger and the Anderson acquisition.

UNAUDITED PRO FORMA BALANCE SHEET
AS OF DECEMBER 31, 2001

	DEVON HISTORICAL	MITCHELL HISTORICAL	MITCHELL PRO FORMA ADJUSTMENTS (NOTE 3)	COMBINED COMPANY PRO FORMA
		(IN THOUSANDS)		
ASSETS:				
Current assets	$ 1,081,272	$ 195,119	$ --	$ 1,276,391
Property and equipment, net	9,028,425	1,658,612	1,496,063(a) (156,785)(d)	12,026,315
Investment in common stock of ChevronTexaco Corporation	635,553	--	--	635,553
Goodwill, net	2,205,844	--	1,388,393(a)	3,594,237
Fair value of derivative instruments	30,582	--	--	30,582
Other assets	202,154	57,707	(385)(a) 11,704(c)	271,180
Total assets	$13,183,830	$1,911,438	$2,738,990	$17,834,258
LIABILITIES:				
Current liabilities	$ 918,971	$ 307,357	$ 88,726(a)	$ 1,315,054
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	648,653	--	--	648,653
Other long-term debt	5,939,781	363,055	1,567,143(c) 11,704(c)	7,881,683
Other long-term liabilities	229,491	101,257	(20,760)(a)	309,988
Fair value of derivative instruments	45,573	--	--	45,573
Deferred income taxes	2,141,874	296,750	559,701(a) (54,875)(d)	2,943,450
STOCKHOLDERS' EQUITY:				
Preferred stock	1,500	--	--	1,500
Common stock	12,989	5,386	2,957(a) (5,386)(b)	15,946
Additional paid-in capital	3,610,484	155,464	1,529,323(a) (155,464)(b)	5,139,807
Retained earnings (accumulated deficit)	(147,017)	766,379	(766,379)(b)	(248,927)
Accumulated other comprehensive loss	(27,782)	(11,321)	11,321(b)	(27,782)
Treasury stock	(190,387)	(72,889)	72,889(b)	(190,387)
Other	(300)	--	--	(300)
Total stockholders' equity	3,259,487	843,019	590,904	4,689,857
Total liabilities and stockholders' equity	$13,183,830	$1,911,438	$2,738,990	$17,834,258

UNAUDITED PRO FORMA STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2001

	DEVON PRO FORMA AFTER ANDERSON ACQUISITION (NOTES 1 AND 8)	MITCHELL HISTORICAL RECLASSIFIED (NOTE 6)	MITCHELL PRO FORMA ADJUSTMENTS (NOTE 3)	COMBINED COMPANY PRO FORMA
	(IN THOUSANDS, EXCEPT PER SHARE DATA)			
REVENUE:				
Oil sales	$1,184,387	$ 48,011	$ --	$1,232,398
Gas sales	2,627,362	517,260	--	3,144,622
NGL sales	218,259	89,634	--	307,893
Marketing and midstream revenue	75,977	1,162,532	--	1,238,509
Other revenue	70,692	28	--	70,720
Total revenue	4,176,677	1,817,465	--	5,994,142
COSTS AND EXPENSES:				
Lease operating expenses	708,517	60,460	--	768,977
Transportation costs	122,254	33,143	--	155,397
Production taxes	121,393	27,614	--	149,007
Exploration expenses	--	18,611	(18,611)(g)	--
Marketing and midstream costs and expenses	49,689	1,034,898	--	1,084,587
Depreciation, depletion and amortization of property and equipment	1,163,558	227,072	12,695(e)	1,403,325
Amortization of goodwill	33,846	--	--	33,846
General and administrative expenses	148,597	61,543	(8,443)(g)	201,697
Expenses related to previous mergers	1,332	--	--	1,332
Interest expense	446,173	15,186	45,600(f)	506,959
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	21,266	--	--	21,266
Change in fair value of derivative instruments	15,576	--	--	15,576
Reduction of carrying value of oil and gas properties	1,003,611	--	156,785(h)	1,160,396
Total costs and expenses	3,835,812	1,478,527	188,026	5,502,365
Earnings before income tax expense	340,865	338,938	(188,026)	491,777
INCOME TAX EXPENSE:				
Current	83,412	11,408	(17,328)(i)	77,492
Deferred	48,210	99,731	(49,849)(i)	98,092
Total income tax expense	131,622	111,139	(67,177)	175,584
Net earnings	209,243	227,799	(120,849)	316,193
Preferred stock dividends	9,735	--	--	9,735
Net earnings applicable to common stockholders	$ 199,508	$ 227,799	$(120,849)	$ 306,458
Net earnings per average common share outstanding:				
Basic	$ 1.56	$ 4.56		$ 1.95
Diluted	1.54	4.48		1.93
Weighted average common shares outstanding:				
Basic	127,712	50,000		156,962
Diluted	133,865	50,889		163,634

NOTES TO UNAUDITED PRO FORMA COMBINED FINANCIAL INFORMATION
DECEMBER 31, 2001

1. BASIS OF PRESENTATION

The accompanying unaudited pro forma balance sheet and statements of operations present the pro forma effects of Devon's January 24, 2002, merger with Mitchell. On October 15, 2001, Devon completed its acquisition of Anderson. Devon paid approximately $3.5 billion to acquire all of Anderson's outstanding common shares and to pay for the intrinsic value of Anderson's outstanding options and appreciation rights. The accompanying unaudited pro forma financial statements present the effect of the Mitchell merger on Devon's financial position and results of operations, assuming that the Anderson acquisition had occurred on January 1, 2001. See Note 8 for the 2001 unaudited pro forma statement of operations that combines, on a pro forma basis, the results of operations of Devon and Anderson.

2. METHOD OF ACCOUNTING FOR THE MERGER

Devon has accounted for the merger using the purchase method of accounting for business combinations. Accordingly, Mitchell's assets acquired and liabilities assumed by Devon were revalued and recorded at their estimated "fair values." In the merger, Devon paid $31.00 in cash and issued 0.585 of a share of Devon common stock for each outstanding share of Mitchell common stock. On a pro forma basis, assuming that the merger had occurred on December 31, 2001, this would have resulted in Devon paying approximately $1.6 billion in cash and issuing approximately 29.6 million shares of its common stock to Mitchell stockholders.

The purchase price of Mitchell's net assets acquired was based on the total value of the cash paid and the Devon common stock issued to the Mitchell stockholders. The value of the Devon common stock issued was based on the average closing price of Devon's common stock for a period of three days before and after the public announcement of the merger. This average closing price equaled $50.95 per share.

3. PRO FORMA ADJUSTMENTS RELATED TO THE MERGER

The unaudited pro forma balance sheet includes the following adjustments:

(a) This entry adjusts the historical book values of Mitchell's assets and liabilities to their estimated fair values as of December 31, 2001. The calculation of the total purchase price and the preliminary allocation to assets and liabilities are shown below.

	(IN THOUSANDS, EXCEPT FOR SHARE PRICE)
Calculation and preliminary allocation of purchase price:	
Shares of Devon common stock to be issued to Mitchell stockholders	29,574
Average Devon stock price	$ 50.95
Fair value of common stock to be issued	1,506,795
Cash to be paid to Mitchell stockholders, calculated at $31 per outstanding common share of Mitchell	1,567,143
Fair value of Devon common stock and cash to be issued to Mitchell stockholders	3,073,938
Plus estimated merger costs to be incurred	90,000
Plus fair value of Mitchell employee stock options to be assumed by Devon	25,485
Total purchase price	3,189,423
Plus fair value of liabilities to be assumed by Devon:	
Current liabilities	306,083
Long-term debt	363,055
Other long-term liabilities	80,497
Deferred income taxes	859,384
Total purchase price plus liabilities assumed	$4,798,442
Fair value of assets to be acquired by Devon:	
Current assets	$ 195,119
Proved oil and gas properties	1,520,886
Unproved oil and gas properties	639,170
Marketing and midstream facilities and equipment	1,000,000
Other property and equipment	3,000
Other assets	57,322
Goodwill	1,382,945
Total fair value of assets to be acquired	$4,798,442

The total purchase price includes the value of the cash and Devon common stock to be issued to Mitchell stockholders. The total purchase price also includes:

- $90.0 million of estimated merger costs. These costs include investment banking expenses, severance, legal and accounting fees, printing expenses and other merger-related costs. These costs have been added to current liabilities in the unaudited pro forma balance sheet.

- $25.5 million of Devon employee stock options to be issued in exchange for existing vested Mitchell employee stock options. The value of these options is added to additional paid-in capital in the unaudited pro forma balance sheet.

The purchase price allocation is preliminary and is subject to change as the final tax bases and fair values are determined of the assets acquired and liabilities assumed.

(b) This adjustment includes a $5.4 million reduction of common stock, a $155.5 million reduction of additional paid-in capital, a $766.4 million reduction of retained earnings, an $11.3 million reduction of accumulated other comprehensive loss and a $72.9 million reduction of treasury stock. These adjustments eliminate the historical book value of Mitchell's stockholders' equity.

(c) This adjustment increases long-term debt by $1.6 billion to include the long-term debt that Devon would have incurred on December 31, 2001, to fund the cash portion of the merger consideration. The debt was borrowed under Devon's $3 billion, variable interest rate, five year credit facility entered into on October 12, 2001. Debt under this facility matures between 2003 and 2005. The adjustment also includes $11.7 million of costs estimated to be incurred in connection with issuing this debt.

(d) This adjustment is for the additional reduction of carrying value of oil and gas properties that would have been recorded as of December 31, 2001, for the merger. This adjustment equals the difference between the fair value of the oil and gas properties at year-end 2001 and the related ceiling allowed under the full cost method of accounting.

The unaudited pro forma statement of operations includes the following adjustments:

(e) This adjustment revises historical depreciation, depletion and amortization to reflect the adjustment of Mitchell's assets from historical book value to fair value and a change to the full cost accounting method from the successful efforts method. For Mitchell's midstream assets acquired, pro forma depreciation expense was calculated using estimated useful lives of approximately 15 years. For Mitchell's oil and gas producing properties acquired, pro forma depreciation, depletion and amortization expense was calculated using the equivalent units-of-production method. Mitchell's proved oil and gas reserves, divided by its annualized production for 2001, yields an estimated reserve life of 14 years. The increase in depreciation, depletion and amortization of $2.7 million is net of the reversal of an impairment charge of $26.0 million recognized by Mitchell under the successful efforts method.

(f) This adjustment increases interest expense due to the $1.6 billion of additional long-term debt. This adjustment has been calculated using an estimated interest rate of 2.89%, plus the amortization of estimated financing costs to be incurred, on the variable rate debt. This assumed interest rate is based on the terms of Devon's $3 billion credit facility. The actual rate will vary with changes in market rates. A change in the interest rate of 0.125% would change the combined company pro forma interest expense by $2.7 million. This change includes the amount related to the debt borrowed under the $3 billion credit facility to fund a portion of the Anderson acquisition as described in Note 8.

(g) This adjustment eliminates historical amounts recognized by Mitchell under the successful efforts accounting method that are not recognized as expenses under the full cost accounting method. Included in this adjustment are costs incurred by Mitchell related to its property exploration activities such as exploratory dry holes and geological and geophysical costs that are expensed as incurred under the successful efforts method followed by Mitchell, but are capitalized under the full cost method followed by Devon. Also included in this adjustment are general and administrative expenses incurred by Mitchell which were directly identified with its acquisition, exploration and development activities undertaken for its own account. These costs are expensed as incurred under the successful efforts method, but are capitalized under the full cost method.

(h) See note (d) above.

(i) This adjustment records the income tax impact of all pro forma adjustments at an effective tax rate of approximately 36%.

4. COMMON SHARES OUTSTANDING

Net earnings per average share outstanding have been calculated based on the pro forma weighted average number of shares outstanding as follows:

	YEAR ENDED DECEMBER 31, 2001
	(IN THOUSANDS)
Basic:	
Devon's weighted average common shares outstanding	127,712
New Devon shares to be issued to Mitchell stockholders	29,250
Pro forma weighted average Devon shares outstanding	156,962
Diluted:	
Devon's weighted average common shares outstanding	133,864
New Devon shares to be issued to Mitchell stockholders	29,770
Pro forma weighted average Devon shares outstanding	163,634

Pro forma shares of Devon common stock outstanding at December 31, 2001, assuming the merger occurred on that date, are as follows:

	(IN THOUSANDS)
Devon's common shares outstanding	126,132
New Devon shares to be issued to Mitchell stockholders	29,574
Pro forma Devon common shares outstanding	155,706

5. GOODWILL

The preliminary pro forma allocation of the purchase price includes approximately $1.4 billion of goodwill. In July 2001, the Financial Accounting Standards Board issued Statement No. 141, "Business Combinations," and Statement No. 142, "Goodwill and Other Intangible Assets." As a result of these two recent pronouncements, goodwill recorded in connection with business combinations completed after June 30, 2001 (including the merger) will not be amortized but, instead, will be tested for impairment at least annually. Accordingly, the accompanying unaudited pro forma statements of operations include no amortization of the goodwill to be recorded in the merger.

Statement No. 142 was adopted by Devon as of January 1, 2002. Until that date, goodwill recognized from business combinations completed prior to June 30, 2001 must continue to be amortized. Therefore, Devon's historical goodwill amortization related to previous mergers has not been reversed in the accompanying unaudited pro forma statements of operations. As of January 1, 2002, goodwill related to these previous mergers will no longer be amortized but, instead, will be tested for impairment at least annually. The accompanying unaudited pro forma statement of operations for the year ended December 31, 2001 includes amortization of goodwill related to previous mergers of $33.8 million.

6. DEVON AND MITCHELL HISTORICAL AND RECLASSIFIED BALANCES

Devon and Mitchell record certain revenue and expenses differently in their respective consolidated financial statements. To make the unaudited pro forma financial information consistent, certain of Devon's and Mitchell's balances have been reclassified to conform presentation.

Devon's historical balances for other revenue have been reclassified to include separate line items for marketing and midstream revenue and marketing and midstream costs and expenses to conform to Mitchell's presentation and Devon's presentation subsequent to the merger.

The following tables present Mitchell's balances as presented in its historical financial statements and the reclassified balances that are included in the accompanying unaudited pro forma statement of operations.

	YEAR ENDED DECEMBER 31, 2001		
	MITCHELL HISTORICAL	RECLASSIFICATIONS	MITCHELL HISTORICAL RECLASSIFIED
		(IN THOUSANDS)	
REVENUE:			
Exploration and production	$ 656,404	$(656,404)	$ --
Oil sales	--	48,011	48,011
Gas sales	--	517,260	517,260
NGL sales	--	89,634	89,634
Marketing and midstream revenue	1,162,532	--	1,162,532
Other revenue	--	28	28
Total revenue	1,818,936	(1,471)	1,817,465
COSTS AND EXPENSES:			
Exploration and production	342,782	(342,782)	--
Lease operating expenses	--	60,460	60,460
Transportation costs	--	33,143	33,143
Production taxes	--	27,614	27,614
Exploration expenses	--	18,611	18,611
Marketing and midstream	1,087,741	(52,843)	1,034,898
Depreciation, depletion and amortization of property and equipment	--	227,072	227,072
General and administrative expenses	32,731	28,812	61,543
Interest expense	22,720	(7,534)	15,186
Other (income) expense, net	(5,976)	5,976	--
Total costs and expenses	1,479,998	(1,471)	1,478,527
Earnings before income taxes	338,938	--	338,938
Income tax expense	111,139	--	111,139
Net earnings	$ 227,799	$ --	$ 227,799

7. MARKETING AND MIDSTREAM INFORMATION

The following table provides certain information relating to the unaudited pro forma marketing and midstream revenues and costs and expenses for the year ended December 31, 2001.

	YEAR ENDED DECEMBER 31, 2001
	(IN THOUSANDS)
MARKETING AND MIDSTREAM REVENUE:	
Gas processing operations:	
Percentage of proceeds NGL volumes (MBbls)	6,870
Keep whole NGL volumes (MBbls)	8,263
Total NGL volumes	15,133
Average NGL price per barrel	$ 18.22
NGL revenue	275,775
NGL marketing and other revenue	389,555
Total gas processing revenue	665,330
Natural gas gathering and marketing revenue	568,336
Other gas services revenue	4,843
Total gas services revenue	$1,238,509
MARKETING AND MIDSTREAM COSTS AND EXPENSES:	
Gas processing operations:	
Percentage of proceeds payments	$ 61,781
Keep whole gas purchased	127,525
Other NGL costs	39,223
Total NGL costs	228,529
NGL marketing and other costs and expenses	367,642
Total gas processing costs and expenses	596,171
Natural gas gathering and marketing costs and expenses	487,839
Other gas services costs and expenses	577
Total gas services costs and expenses	$1,084,587

Natural gas gathering and marketing margins (natural gas gathering and marketing revenue less natural gas gathering and marketing costs and expenses) were unusually high in the year 2001. After the merger, Devon expects the combined company's natural gas gathering and marketing margin to approximate between $30 million and $40 million per year.

The above table contains the terms "percentage of proceeds" and "keep whole." These terms refer to two different types of contracts involving processing natural gas. Under a percentage of proceeds contract, the buyer and seller share in the net proceeds from the sale of all NGLs and residue gas allocated to the seller after reductions for fuel use, line loss and processing shrink. Residue gas refers to that portion of the seller's natural gas that remains after processing.

A keep whole contract allows the seller to sell 100% of the BTUs it delivers at the wellhead even though the natural gas is being processed to extract NGLs. To do this, the buyer must deliver to the seller an equivalent amount of BTUs as were extracted from the gas at the processing plant or reimburse the seller the value of the gas extracted. This is referred to as "keep whole gas" in the above table. The seller receives its allocation of residue gas plus the keep whole gas from the buyer, so that the seller's total wellhead BTUs are "kept whole". In this type of agreement, the buyer bears the processing risk, in that the total revenues received from the NGLs sold must exceed the cost of the keep whole gas for the buyer to have a positive margin.

8. UNAUDITED PRO FORMA EFFECT OF ANDERSON ACQUISITION

The following presents the pro forma effect of the October 15, 2001, Anderson acquisition on Devon's historical statement of operations for the year ended December 31, 2001. The column headed "Devon Historical Reclassified" includes the effect of the Anderson acquisition from October 15, 2001, through December 31, 2001. The column headed "Anderson Historical Reclassified U.S. GAAP" includes Anderson's results of operations for the nine months ended September 30, 2001. The column headed "Pro Forma Adjustments" includes adjustment (e) which accounts for Anderson's results of operations for the first fourteen days of October 2001. The column headed "Devon Pro Forma After Anderson Acquisition" represents Devon's pro forma results for 2001 assuming the Anderson Acquisition had occurred on January 1, 2001.

Anderson's historical amounts presented in the following statement have been converted to accounting principles generally accepted in the United States and to U.S. dollars. For information on such conversions, see Note 9.

Devon has accounted for the Anderson acquisition using the purchase method of accounting for business combinations. Accordingly, Anderson's assets acquired and liabilities assumed by Devon were revalued and recorded at their estimated "fair values." In the Anderson acquisition, Devon paid C$40 per share for each outstanding common share, including associated rights, of Anderson. This resulted in Devon paying approximately $3.4 billion in cash to Anderson stockholders, as well as an additional $0.1 billion of cash paid to Anderson employees for the intrinsic value of outstanding stock options and appreciation rights. These U.S. dollar amounts are based on the October 15, 2001 exchange rate of C$1.00 to U.S.$0.6419.

DEVON-ANDERSON

UNAUDITED PRO FORMA STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2001

	DEVON HISTORICAL RECLASSIFIED (NOTE 6)	ANDERSON HISTORICAL RECLASSIFIED U.S. GAAP (NOTE 9)	PRO FORMA ADJUSTMENTS	DEVON PRO FORMA AFTER ANDERSON ACQUISITION
	(IN THOUSANDS, EXCEPT PER SHARE DATA)			
REVENUE:				
Oil sales	$ 957,666	$218,733	$ 7,988(e)	$1,184,387
Gas sales	1,889,788	720,241	17,333(e)	2,627,362
NGL sales	132,571	82,754	2,934(e)	218,259
Marketing and midstream revenue	69,764	5,950	263(e)	75,977
Other	72,016	(1,248)	(243)(d) 167(e)	70,692
Total revenues	3,121,805	1,026,430	28,442	4,176,677
COSTS AND EXPENSES:				
Lease operating expenses	531,025	169,191	8,301(e)	708,517
Transportation costs	82,819	37,444	1,991(e)	122,254
Production taxes	116,788	4,459	146(e)	121,393
Marketing and midstream costs and expenses	46,595	3,094	--	49,689
Depreciation, depletion and amortization of property and equipment	876,250	257,482	15,239(a) 14,587(e)	1,163,558
Amortization of goodwill	33,846	--	--	33,846
General and administrative expenses	111,068	36,350	1,179(e)	148,597
Expenses related to previous mergers	1,332	--	--	1,332
Interest expense	220,137	49,780	181,909(b) (17,021)(c) 11,368(e)	446,173
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	12,588	14,719	(6,041)(e)	21,266
Change in fair value of derivative instruments	1,924	13,652	--	15,576
Reduction of carrying value of oil and gas properties	1,003,611	--	--	1,003,611
Total costs and expenses	3,037,983	586,171	211,658	3,835,812
Earnings before income tax expense	83,822	440,259	(183,216)	340,865
INCOME TAX EXPENSE:				
Current	70,852	13,201	(641)(f)	83,412
Deferred	(40,623)	155,932	(67,099)(f)	48,210
Total income tax expense	30,229	169,133	(67,740)(f)	131,622
Net earnings before cumulative effect of change in accounting principle	53,593	271,126	(115,476)	209,243
Preferred stock dividends	9,735	--	--	9,735
Net earnings applicable to common stockholders	$ 43,858	$271,126	$(115,476)	$ 199,508
Net earnings per average common share outstanding:				
Basic	$ 0.34			$ 1.56
Diluted	0.34			1.54
Weighted average common shares outstanding:				
Basic	127,712			127,712
Diluted	133,864			133,864

PRO FORMA ADJUSTMENTS RELATED TO THE ANDERSON ACQUISITION

The Devon-Anderson unaudited pro forma statement of operations included in this note includes the following adjustments:

(a) This adjustment increases historical depreciation, depletion and amortization expense to reflect the adjustment of Anderson's assets from historical book value to fair value. For Anderson's oil and gas producing properties acquired, pro forma depreciation, depletion and amortization expense was calculated using the equivalent units-of-production method. Anderson's proved oil and gas reserves, divided by its annualized production, yields an estimated reserve life of ten years.

(b) This adjustment increases interest expense due to the $3.5 billion of long-term debt that Devon would have incurred at January 1, 2001, to fund the Anderson acquisition. This adjustment has been calculated using an average interest rate of 7.4% on the $3.0 billion of fixed rate debt, and an estimated rate of 3.17%, plus the amortization of estimated financing costs, on the $0.5 billion of variable rate debt. The assumed interest rate on the variable rate debt is based on the terms of Devon's $3 billion credit facility. The actual rates on this variable rate debt will vary with changes in market rates. A change in the interest rate of 0.125% would change the pro forma interest expense by $0.8 million.

(c) This adjustment reduces interest expense to reflect the repayment of Anderson's bank debt with debt borrowed under Devon's $3 billion credit facility that bears a lower interest rate, plus a decrease in interest expense related to the effect of valuing Anderson's fixed-rate debt at the estimated fair value of such debt. The adjustment relating to the repayment of Anderson's bank debt reduced interest expense for the first nine months of 2001 by $15.2 million. The adjustment relating to recording Anderson's fixed-rate debt at fair value decreased interest expense for the first nine months of 2001 by $1.8 million.

(d) This adjustment reduces the Alberta Royalty Tax Credit as a result of the acquisition of Anderson.

(e) This adjustment includes Anderson's revenues and expenses for the first 14 days of October 2001 prior to its acquisition by Devon on October 15, 2001.

(f) This adjustment records the income tax impact of all pro forma adjustments at an effective tax rate of approximately 37%. The rate includes the effect of a change in Canadian tax rates enacted during the second quarter of 2001. Excluding the retroactive effect of this rate change, the rate applied to the 2001 pro forma adjustments would have been 40%.

GOODWILL

The October 15, 2001, allocation of the purchase price for the Anderson acquisition included approximately $2.0 billion of goodwill. In July 2001, the Financial Accounting Standards Board issued Statement No. 141, "Business Combinations," and Statement No. 142, "Goodwill and Other Intangible Assets." As a result of these two recent pronouncements, goodwill recorded in connection with business combinations completed after June 30, 2001 (including the Anderson acquisition) will not be amortized but, instead, will be tested for impairment at least annually. Accordingly, the Devon-Anderson unaudited pro forma statement of operations included in this note includes no amortization of the goodwill recorded in the Anderson acquisition.

Statement No. 142 was adopted by Devon as of January 1, 2002. Until that date, goodwill recognized from business combinations completed prior to June 30, 2001 must continue to be amortized. Therefore, Devon's historical goodwill related to previous mergers has not been reversed in the Devon-Anderson unaudited pro forma statement of operations included in this note. As of January 1, 2002, goodwill related to these previous mergers will no longer be amortized but, instead, will be tested for impairment at least annually. The Devon-Anderson unaudited pro forma statement of operations included in this note for the year ended December 31, 2001 includes amortization of goodwill related to previous mergers of $33.8 million.

9. CONVERSION OF ANDERSON'S HISTORICAL FINANCIAL STATEMENTS

Anderson prepared its historical financial statements based on a fiscal year of September 30. To conform to Devon's year-end of December 31, Anderson's historical results for the year ended September 30, 2001 were converted to results for the nine months ended September 30, 2001. This conversion was done by subtracting Anderson's historical interim results for the three months ended December 31, 2000.

Anderson prepared its historical financial statements using accounting principles generally accepted in Canada ("Canadian GAAP") and Canadian dollars. The following tables provide information relating to the conversion of Anderson's historical financial statements to those prepared using accounting principles generally accepted in the United States ("U.S. GAAP") and U.S. dollars.

ANDERSON UNAUDITED U.S. GAAP STATEMENT OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2001

	ANDERSON HISTORICAL C$	U.S. GAAP AND OTHER ADJUSTMENTS C$	ANDERSON U.S. GAAP C$	CONVERTED TO U.S.$
	(IN THOUSANDS, EXCEPT PER SHARE DATA)			
REVENUE:				
Oil sales	C$ 397,832	C$ (61,371)(a)	C$ 336,461	$218,733
Gas sales	1,396,195	(288,302)(a)	1,107,893	720,241
NGL sales	155,668	(28,373)(a)	127,295	82,754
Less royalties	(448,920)	448,920(a)	--	--
Gas services revenue	--	9,152(a)	9,152	5,950
Other	4,499	(6,418)(a)	(1,919)	(1,248)
Total revenues	1,505,274	73,608	1,578,882	1,026,430
COSTS AND EXPENSES:				
Lease operating expenses	255,861	4,393(a)	260,254	169,191
Transportation costs	--	57,597(a)	57,597	37,444
Production taxes	--	6,859(a)	6,859	4,459
Gas services costs and expenses	--	4,759(a)	4,759	3,094
Depreciation, depletion and amortization of property and equipment	421,165	(44,200)(b) 19,100(d)	396,065	257,482
General and administrative expenses	55,915	--	55,915	36,350
Interest expense	81,114	(4,541)(c)	76,573	49,780
Deferred effect of changes in foreign currency exchange rate on long-term debt	--	22,641(c)	22,641	14,719
Change in fair value of derivative instruments	--	21,000 (e)	21,000	13,652
Total costs and expenses	814,055	87,608	901,663	586,171
Earnings before income tax expense	691,219	(14,000)	677,219	440,259
INCOME TAX EXPENSE:				
Current	20,306	--	20,306	13,201
Deferred	242,609	(2,750)(f)	239,859	155,932
Total income tax expense	262,915	(2,750)	260,165	169,133
Net earnings	C$ 428,304	C$ (11,250)	C$ 417,054	$271,126
Net earnings per average common share outstanding:				
Basic	C$ 3.26		C$ 3.18	$ 2.07
Diluted	3.19		3.11	2.02
Weighted average common shares outstanding:				
Basic	131,241		131,241	131,241
Diluted	134,187		134,187	134,187

The following adjustments convert Anderson's Canadian GAAP statements of operating results to U.S. GAAP statements of operating results:

(a) This adjustment (1) allocates oil, gas and NGL royalty payments to oil, gas and NGL revenues in accordance with U.S. GAAP; (2) reclassifies third party processing revenues from lease operating expenses to gas services revenues and expenses, and freehold mineral taxes from royalties to production taxes, to conform to Devon's presentation; and (3) reclassifies transportation costs which are netted against oil, gas and NGL sales in Anderson's historical results as expenses in accordance with U.S. GAAP.

(b) This adjustment records the impact of a lower depreciation, depletion and amortization rate for U.S. GAAP as a result of a reduction in carrying value of oil and gas properties which Anderson would have recognized in 1998 due to a U.S. full cost ceiling limitation.

(c) This adjustment recognizes foreign exchange losses on long-term debt in accordance with U.S. GAAP.

(d) This adjustment reflects additional depreciation, depletion and amortization resulting from the accounting for the initial adoption of the liability method of accounting for income taxes as an adjustment to property and equipment.

(e) This adjustment records the impact of changes in the fair value of derivative instruments that do not qualify as hedges under U.S. GAAP.

(f) This adjustment records the income tax impact of all the U.S. GAAP adjustments described above.

For the U.S. GAAP statement of operations for the nine months ended September 30, 2001, Canadian dollars were converted to U.S. dollars using the exchange rate of $0.6501. Such rate is the average of the month end exchange rates for the nine-month period.

10. REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES

Under the full cost method of accounting, the net book value of oil and gas properties less related deferred income taxes (the "cost to be recovered"), may not exceed a calculated "full cost ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from oil and gas properties. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense, except as discussed in the following paragraph.

If, subsequent to the end of the quarter but prior to the applicable financial statements being published, prices increase to levels such that the ceiling would exceed the costs to be recovered, a write down otherwise indicated at the end of the quarter is not required to be recorded. A write down indicated at the end of a quarter is also not required if the value of additional reserves proved up on properties after the end of the quarter but prior to the publishing of the financial statements would result in the ceiling exceeding the costs to be recovered, as long as the properties were owned at the end of the quarter.

An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Based on oil and natural gas cash market prices as of December 31, 2001, the combined company's pro forma domestic, Canadian and Egyptian costs to be recovered exceeded the related ceiling values by $383.3 million, $252.0 million and $23.1 million, respectively. These after-tax amounts would have resulted in pro forma pre-tax reductions of the carrying values of the combined company's domestic and Canadian oil and gas properties of $605.5 million, $434.1 million, and $32.9 million, respectively, in the fourth quarter of 2001.

The combined company pro forma results for 2001 include a reduction of the carrying value of oil and gas properties related to Devon's decision to discontinue its operations in Malaysia, Qatar, Thailand and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, Devon determined that the properties did not meet Devon's internal criteria to justify further investment. Accordingly, during the first nine months of 2001, Devon recorded a pre-tax charge on $87.9 million ($68.8 million after-tax) associated with the impairment of these international properties.

11. SUPPLEMENTAL PRO FORMA INFORMATION ON OIL AND GAS OPERATIONS

The following pro forma supplemental information regarding oil and gas operations is presented pursuant to the disclosure requirements of Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities."

Pro Forma Costs Incurred

The following tables reflect the costs incurred in oil and gas property acquisition, exploration and development activities of Devon, Mitchell and the combined company on a pro forma basis, for the year ended December 31, 2001. The "Devon Pro Forma" amounts assume the Anderson acquisition had occurred on December 31, 2000.

	DEVON PRO FORMA	MITCHELL	COMBINED COMPANY	DEVON PRO FORMA	MITCHELL	COMBINED COMPANY
	(IN MILLIONS)					
	TOTAL			DOMESTIC		
Property acquisition costs:						
Proved	$1,169	$ 6	$1,175	$371	$ 6	$ 377
Unproved	429	20	449	185	20	205
Exploration costs	621	25	646	166	25	191
Development costs	1,216	446	1,662	726	446	1,172
	CANADA			INTERNATIONAL		
Property acquisition costs:						
Proved	$ 736	$ --	$ 736	$ 62	$ --	$ 62
Unproved	243	--	243	1	--	1
Exploration costs	391	--	391	64	--	64
Development costs	406	--	406	84	--	84

Pro Forma Quantities of Oil and Gas Reserves

The following tables set forth the changes in the net quantities of oil, natural gas and NGL reserves of Devon, Mitchell and the combined company on a pro forma basis, for the year ended December 31, 2001. The "Devon Pro Forma" amounts assume the Anderson acquisition had occurred on December 31, 2000.

	DEVON PRO FORMA	MITCHELL	COMBINED COMPANY	DEVON PRO FORMA	MITCHELL	COMBINED COMPANY
	TOTAL OIL -- MMBBLS			DOMESTIC OIL -- MMBBLS		
Proved reserves as of December 31, 2000	560	12	572	226	12	238
Revisions of estimates	(8)	(2)	(10)	(25)	(2)	(27)
Extensions and discoveries	38	3	41	12	3	15
Purchase of reserves	75	--	75	15	--	15
Production	(55)	(1)	(56)	(26)	(1)	(27)
Sale of reserves	(24)	--	(24)	(11)	--	(11)
Proved reserves as of December 31, 2001	586	12	598	191	12	203
Proved developed reserves as of:						
December 31, 2000	332	11	343	192	11	203
December 31, 2001	324	10	334	167	10	177

	CANADA OIL -- MMBBLS			INTERNATIONAL OIL -- MMBBLS		
Proved reserves as of December 31, 2000	137	--	137	197	--	197
Revisions of estimates	6	--	6	11	--	11
Extensions and discoveries	12	--	12	14	--	14
Purchase of reserves	42	--	42	18	--	18
Production	(19)	--	(19)	(10)	--	(10)
Sale of reserves	(12)	--	(12)	(1)	--	(1)
Proved reserves as of December 31, 2001	166	--	166	229	--	229
Proved developed reserves as of:						
December 31, 2000	101	--	101	39	--	39
December 31, 2001	124	--	124	33	--	33

	TOTAL GAS -- MMCF			DOMESTIC GAS -- MMCF		
Proved reserves as of December 31, 2000	5,248	1,263	6,511	2,521	1,263	3,784
Revisions of estimates	(321)	(7)	(328)	(262)	(7)	(269)
Extensions and discoveries	854	598	1,452	360	598	958
Purchase of reserves	387	2	389	170	2	172
Production	(673)	(137)	(810)	(376)	(137)	(513)
Sale of reserves	(18)	--	(18)	(14)	--	(14)
Proved reserves as of December 31, 2001	5,477	1,719	7,196	2,399	1,719	4,118
Proved developed reserves as of:						
December 31, 2000	3,845	659	4,504	2,087	659	2,746
December 31, 2001	3,948	887	4,835	1,988	887	2,875

	DEVON PRO FORMA	MITCHELL	COMBINED COMPANY	DEVON PRO FORMA	MITCHELL	COMBINED COMPANY
	CANADA GAS -- MMCF			INTERNATIONAL GAS -- MMCF		
Proved reserves as of December 31, 2000	2,314	--	2,314	413	--	413
Revisions of estimates	(28)	--	(28)	(31)	--	(31)
Extensions and discoveries	414	--	414	80	--	80
Purchase of reserves	217	--	217	--	--	--
Production	(288)	--	(288)	(9)	--	(9)
Sale of reserves	(4)	--	(4)	--	--	--
Proved reserves as of December 31, 2001	2,625	--	2,625	453	--	453
Proved developed reserves as of:						
December 31, 2000	1,722	--	1,722	36	--	36
December 31, 2001	1,923	--	1,923	37	--	37

	TOTAL NGLS -- MBBLS			DOMESTIC NGLS -- MBBLS		
Proved reserves as of December 31, 2000	109	59	168	46	59	105
Revisions of estimates	3	6	9	7	6	13
Extensions and discoveries	14	31	45	5	31	36
Purchase of reserves	7	--	7	--	--	--
Production	(12)	(6)	(18)	(6)	(6)	(12)
Sale of reserves	--	--	--	--	--	--
Proved reserves as of December 31, 2001	121	90	211	52	90	142
Proved developed reserves as of:						
December 31, 2000	80	27	107	42	27	69
December 31, 2001	88	42	130	48	42	90

	CANADA NGLS -- MBBLS			INTERNATIONAL NGLS -- MBBLS		
Proved reserves as of December 31, 2000	51	--	51	12	--	12
Revisions of estimates	(3)	--	(3)	(1)	--	(1)
Extensions and discoveries	7	--	7	2	--	2
Purchase of reserves	7	--	7	--	--	--
Production	(6)	--	(6)	--	--	--
Sale of reserves	--	--	--	--	--	--
Proved reserves as of December 31, 2001	56	--	56	13	--	13
Proved developed reserves as of:						
December 31, 2000	38	--	38	--	--	--
December 31, 2001	40	--	40	--	--	--

Pro Forma Standardized Measure of Discounted Future Net Cash Flows

The following tables set forth the standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGL reserves for Devon, Mitchell and the combined company on a pro forma basis, as of December 31, 2001.

	DEVON	MITCHELL	COMBINED COMPANY	DEVON	MITCHELL	COMBINED COMPANY
	(IN MILLIONS)					
	TOTAL			DOMESTIC		
Future cash inflows	$23,790	$ 5,131	$28,921	$ 9,861	$ 5,131	$14,992
Future costs:						
Development	(2,228)	(951)	(3,179)	(793)	(951)	(1,744)
Production	(8,424)	(1,740)	(10,164)	(3,774)	(1,740)	(5,514)
Future income tax expense	(3,403)	(767)	(4,170)	(759)	(767)	(1,526)
Future net cash flows	9,735	1,673	11,408	4,535	1,673	6,208
10% discount to reflect timing of cash flows	(4,421)	(802)	(5,223)	(1,734)	(802)	(2,536)
Standardized measure of discounted future net cash flows	$ 5,314	$ 871	$ 6,185	$ 2,801	$ 871	$ 3,672
	CANADA			INTERNATIONAL		
Future cash inflows	$ 9,011	$ --	$ 9,011	$ 4,918	$ --	$ 4,918
Future costs:						
Development	(922)	--	(922)	(513)	--	(513)
Production	(3,292)	--	(3,292)	(1,358)	--	(1,358)
Future income tax expense	(2,006)	--	(2,006)	(638)	--	(638)
Future net cash flows	2,791	--	2,791	2,409	--	2,409
10% discount to reflect timing of cash flows	(1,195)	--	(1,195)	(1,492)	--	(1,492)
Standardized measure of discounted future net cash flows	$ 1,596	$ --	$ 1,596	$ 917	$ --	$ 917

Future cash inflows are computed by applying year-end prices to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end. These year-end prices are adjusted for transportation and other charges, and for geographic differentials. The December 31, 2001 NYMEX oil price and Henry Hub gas price, upon which the combined company's actual net prices were based before relevant adjustments, were $19.84 per barrel and $2.65 per Mcf, respectively.

Pro Forma Changes Relating to the Standardized Measure of Discounted Future Net Cash Flows

The following table includes the components of the changes in the standardized measure of discounted future net cash flows of Devon, Mitchell and the combined company on a pro forma basis, for the year ended December 31, 2001. The "Devon Pro Forma" amounts assume the Anderson acquisition had occurred on December 31, 2000.

	DEVON PRO FORMA	MITCHELL	COMBINED COMPANY
		(IN MILLIONS)	
Beginning balance	$ 17,114	$ 3,956	$ 21,070
Sales of oil, gas and NGLs, net of production costs	(3,078)	(534)	(3,612)
Net changes in prices and production costs	(17,766)	(5,121)	(22,887)
Extensions, discoveries, and improved recovery, net of future development costs	925	247	1,172
Purchase of reserves, net of future development costs	681	2	683
Development costs incurred during the period which reduced future development costs	430	260	690
Revisions of quantity estimates	(481)	(26)	(507)
Sales of reserves in place	(158)	--	(158)
Accretion of discount	1,774	601	2,375
Net change in income taxes	6,594	1,649	8,243
Other, primarily changes in timing	(721)	(163)	(884)
Ending balance	$ 5,314	$ 871	$ 6,185

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 hereunto duly authorized.

DEVON ENERGY CORPORATION

Dated: July 17, 2002

By: /s/ Danny J. Heatly

Name: Danny J. Heatly
Title: Vice President
