DEVON ENERGY CORP/DE

FORM 10-Q
(Quarterly Report)

Filed 11/13/03 for the Period Ending 09/30/03

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 10-Q
(Quarterly Report)

Filed 11/13/2003 For Period Ending 9/30/2003

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

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2003

or

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

Commission File No. 000-30176

Devon Energy Corporation

(Exact Name of Registrant as Specified in its Charter)

Delaware	**73-1567067**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification Number)*
20 North Broadway Oklahoma City, Oklahoma	**73102-8260**
(Address of Principal Executive Offices)	*(Zip Code)*

Registrant’s telephone number, including area code:
(405) 235-3611

Former name, former address and former fiscal year, if changed from last report.
Not applicable

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

The number of shares outstanding of Registrant’s common stock, par value $.10, as of October 31, 2003, was 232,557,000.

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to the Securities and Exchange Commission

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DEFINITIONS

As used in this document:

"AECO" means the price of gas delivered onto the NOVA Gas Transmission Ltd. System.

"Bbl" or "Bbls" means barrel or barrels.

"Bcf" means one billion cubic feet.

"Boe" means barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

"Brent" means pricing point for selling North Sea crude oil.

"Btu" means British Thermal units, a measure of heating value.

"Inside FERC" refers to the publication *Inside F.E.R.C.'s Gas Market Report* .

"LIBOR" means London Interbank Offered Rate.

"MMBbls" means one million barrels.

"MMBoe" means one million Boe.

"MMBtu" means one million Btu.

"Mcf" means one thousand cubic feet.

"NGL" or "NGLs" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"Oil" includes crude oil and condensate.

DEVON ENERGY CORPORATION

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2003 and 2002

**(Forming a part of Form 10-Q Quarterly Report
to the Securities and Exchange Commission)**

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	September 30, 2003	December 31, 2002
	(Unaudited) (In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 840	$ 292
Accounts receivable	896	639
Inventories	77	26
Fair value of financial instruments	20	4
Income taxes receivable	11	56
Assets of discontinued operations	—	7
Investments and other current assets	63	40
Total current assets	1,907	1,064
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,339 and $2,289 excluded from amortization in 2003 and 2002, respectively)	27,368	18,786
Less accumulated depreciation, depletion and amortization	9,520	7,934
	17,848	10,852
Investment in ChevronTexaco Corporation common stock, at fair value	507	472
Fair value of financial instruments	26	1
Goodwill	5,341	3,555
Other assets	338	281
Total assets	$25,967	$16,225
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 633	$ 376
Revenues and royalties due to others	331	261
Income taxes payable	83	9
Current portion of long-term debt	340	—
Accrued interest payable	95	119
Merger related expenses payable	21	12
Fair value of financial instruments	72	151
Current portion of asset retirement obligation	32	—
Accrued expenses and other current liabilities	99	114
Total current liabilities	1,706	1,042
Other liabilities	404	323
Asset retirement obligation, long-term	619	—
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	673	662
Other long-term debt	7,908	6,900
Preferred stock of a subsidiary	55	—
Deferred revenue	70	—
Fair value of financial instruments	16	18
Deferred income taxes	4,326	2,627
Stockholders' equity:		
Preferred stock of $1.00 par value ($100 liquidation value) Authorized 4,500,000 shares; issued 1,500,000 in 2003 and 2002	1	1
Common stock of $0.10 par value Authorized 800,000,000 shares; issued 236,203,000 in 2003 and 160,461,000 in 2002	24	16
Additional paid-in capital	8,899	5,178
Retained earnings (accumulated deficit)	1,085	(84)
Accumulated other comprehensive income (loss)	368	(267)
Other	—	(3)
Treasury stock at cost: 3,700,000 shares in 2003 and 3,704,000 shares in 2002	(187)	(188)

Total stockholders’ equity	10,190	4,653
Total liabilities and stockholders’ equity	$25,967	$16,225

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(Unaudited) (In millions, except per share amounts)			
Revenues				
Oil sales	$ 469	$ 217	$1,104	$ 687
Gas sales	1,049	480	2,930	1,508
Natural gas liquids sales	95	69	294	196
Marketing and midstream revenues	335	265	1,104	692
Total revenues	1,948	1,031	5,432	3,083
Production and operating costs and expenses				
Lease operating expenses	238	152	626	468
Transportation costs	57	39	149	115
Production taxes	54	25	152	80
Marketing and midstream operating costs and expenses	268	212	901	559
Depreciation, depletion and amortization of property and equipment	508	282	1,231	916
Accretion of asset retirement obligation	10	—	26	—
General and administrative expenses	79	47	221	151
Expenses related to mergers	—	—	7	—
Reduction of carrying value of oil and gas properties	—	—	—	651
Total production and operating costs and expenses	1,214	757	3,313	2,940
Earnings from operations	734	274	2,119	143
Other income (expenses)				
Interest expense	(120)	(130)	(380)	(402)
Dividends on subsidiary’s preferred stock	—	—	(1)	—
Effects of changes in foreign currency exchange rates	1	(17)	52	—
Change in fair value of financial instruments	(1)	21	8	28
Other income	4	2	29	23
Net other expenses	(116)	(124)	(292)	(351)
Earnings (loss) from continuing operations before income tax expense and cumulative effect of change in accounting principle	618	150	1,827	(208)
Income tax expense (benefit)				
Current	41	36	165	122
Deferred	165	2	474	(294)
Total income tax expense (benefit)	206	38	639	(172)
Earnings (loss) from continuing operations before cumulative effect of change in accounting principle	412	112	1,188	(36)
Discontinued operations				
Results of discontinued operations before income taxes	—	(48)	—	64
Total income tax expense	—	2	—	8
Net results of discontinued operations	—	(50)	—	56
Earnings before cumulative effect of change in accounting principle	412	62	1,188	20
Cumulative effect of change in accounting principle, net of income tax expense of $10 million	—	—	16	—
Net earnings	412	62	1,204	20
Preferred stock dividends	2	2	7	7
Net earnings applicable to common stockholders	$ 410	$ 60	$1,197	$ 13

Basic earnings (loss) per share:				
Earnings (loss) from continuing operations	$ 1.76	$ 0.70	$ 5.89	$ (0.28)
Net results of discontinued operations	—	(0.32)	—	0.36
Cumulative effect of change in accounting principle	—	—	0.08	—
Net earnings applicable to common stockholders	$ 1.76	$ 0.38	$ 5.97	$ 0.08
Diluted earnings (loss) per share:				
Earnings (loss) from continuing operations	$ 1.71	$ 0.68	$ 5.69	$ (0.28)
Net results of discontinued operations	—	(0.31)	—	0.36
Cumulative effect of change in accounting principle	—	—	0.07	—
Net earnings applicable to common stockholders	$ 1.71	$ 0.37	$ 5.76	$ 0.08
Weighted average common shares outstanding — basic	232	156	200	154
Weighted average common shares outstanding — diluted	241	158	209	156

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(Unaudited) (In millions)			
Net earnings	$412	$ 62	$1,204	$ 20
Other comprehensive income (loss), net of tax:				
Foreign currency translation adjustments [1]	19	(167)	560	33
Reclassification adjustment for derivative losses (gains) reclassified into oil and gas sales [2]	34	(10)	165	(51)
Change in fair value of outstanding hedging positions [3]	70	(43)	(112)	(167)
Unrealized gains (losses) on marketable securities [4]	(4)	(83)	22	(88)
Comprehensive income (loss)	$531	$(241)	$1,839	$(253)
[1] net of income tax expense of:	$ (4)	$ —	$ (123)	$ —
[2] net of income tax (expense) benefit of:	(25)	6	(107)	30
[3] net of income tax (expense) benefit of:	(51)	23	62	80
[4] net of income tax benefit (expense) of:	2	49	(13)	52

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2003	2002
	(Unaudited) (In millions)	
Cash flows from operating activities		
Earnings (loss) from continuing operations	$ 1,188	$ (36)
Adjustments to reconcile earnings (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization of property and equipment	1,231	916
Accretion of asset retirement obligation	26	—
Accretion of discounts on long-term debt, net	15	24
Reduction of carrying value of oil and gas properties	—	651
Effects of changes in foreign currency exchange rates	(52)	—
Change in fair value of derivative instruments	(8)	(28)
Deferred income tax expense (benefit)	474	(294)
Operating cash flows of discontinued operations	—	(39)
Loss (gain) on sale of assets	2	(1)
Other	(25)	(6)
Changes in assets and liabilities, net of acquisitions of businesses:		
(Increase) decrease in:		
Accounts receivable	(122)	(14)
Inventories	(13)	5
Investments and other current assets	(10)	(21)
Increase (decrease) in:		
Accounts payable	19	(78)
Income taxes payable	126	161
Accrued interest and expenses	(34)	(9)
Deferred revenue	(32)	(44)
Long-term other liabilities	(5)	(11)
Net cash provided by operating activities	2,780	1,176
Cash flows from investing activities		
Proceeds from sale of property and equipment	40	1,312
Capital expenditures, including acquisitions of businesses	(1,805)	(3,038)
Discontinued operations	—	(19)
Other	—	(4)
Net cash used in investing activities	(1,765)	(1,749)
Cash flows from financing activities		
Proceeds from borrowings of long-term debt, net of issuance costs	598	5,527
Principal payments on long-term debt	(1,118)	(5,018)
Issuance of common stock, net of issuance costs	51	19
Bond issuance	—	(21)
Dividends paid on common stock	(28)	(23)
Dividends paid on preferred stock	(7)	(7)
Net cash (used in) provided by financing activities	(504)	477
Effect of exchange rate changes on cash	37	1
Net increase (decrease) in cash and cash equivalents	548	(95)
Cash and cash equivalents at beginning of period	292	183
Cash and cash equivalents at end of period	$ 840	$ 88

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

The accompanying consolidated financial statements and notes thereto of Devon Energy Corporation (“Devon”) have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission. Accordingly, certain disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted. The accompanying consolidated financial statements and notes thereto should be read in conjunction with the consolidated financial statements and notes thereto included in Devon’s 2002 Annual Report on Form 10-K.

In the opinion of Devon’s management, all adjustments (all of which are normal and recurring) have been made which are necessary to fairly state the consolidated financial position of Devon and its subsidiaries as of September 30, 2003, and the results of their operations and their cash flows for the three-month and nine-month periods ended September 30, 2003 and 2002. Certain of the 2002 amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2003 presentation.

2. Business Combinations and Pro Forma Information

Ocean Energy Inc.

On April 25, 2003, Devon completed its merger with Ocean Energy Inc. (“Ocean”). In the transaction, Devon issued 0.414 shares of its common stock for each outstanding share of Ocean common stock (or a total of approximately 74 million shares). Also, Devon assumed approximately $1.8 billion of debt (current and long-term) from Ocean.

Devon acquired Ocean for the significant development projects and exploration prospects in both the deepwater Gulf of Mexico and internationally, and the additional producing assets onshore United States and in the shallower shelf regions of the Gulf of Mexico.

The calculation of the purchase price and the preliminary allocation to assets and liabilities as of April 25, 2003, are shown below. The purchase price allocation is preliminary because certain items such as the determination of the final tax bases and the fair value of certain assets and liabilities as of the acquisition date have not been completed.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

	(In millions, except share price)
Calculation and preliminary allocation of purchase price:	
Shares of Devon common stock issued to Ocean stockholders	74
Average Devon stock price	$48.05
Fair value of common stock issued	$3,546
Plus estimated merger costs incurred	104
Plus fair value of Ocean convertible preferred stock assumed by a Devon subsidiary	64
Plus fair value of Ocean employee stock options assumed by Devon	124
Total purchase price	3,838
Plus fair value of liabilities assumed by Devon:	
Current liabilities	640
Long-term debt	1,436
Deferred revenue	97
Asset retirement obligation, long-term	121
Other noncurrent liabilities	74
Deferred income taxes	829
Total purchase price plus liabilities assumed	$7,035
Fair value of assets acquired by Devon:	
Current assets	269
Proved oil and gas properties	4,132
Unproved oil and gas properties	1,060
Other property and equipment	79
Other noncurrent assets	37
Goodwill (none deductible for income taxes)	1,458
Total fair value of assets acquired	$7,035

Pro Forma Information

Set forth in the following table is certain unaudited pro forma financial information for the nine-month periods ended September 30, 2003 and 2002. The information for the nine-month periods ended September 30, 2003 and 2002, has been prepared assuming the Ocean merger and the January 24, 2002, Mitchell Energy & Development Corp. merger were consummated on January 1, 2002. All pro forma information is based on estimates and assumptions deemed appropriate by Devon. The pro forma information is presented for illustrative purposes only. If the transactions had occurred in the past, Devon's operating results might have been different from those presented in the following table. The pro forma information should not be relied upon as an indication of the operating results that Devon would have achieved if the transactions had occurred on January 1, 2002. The pro forma information also should not be used as an indication of the future results that Devon will achieve after the transactions.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

	Pro Forma Information Nine Months Ended September 30,	
	2003	2002
	(In millions, except per share amounts and production volumes)	
Revenues		
Oil sales	$1,355	$1,150
Gas sales	3,188	1,874
Natural gas liquids sales	302	218
Marketing and midstream revenues	1,104	764
Total revenues	5,949	4,006
Production and operating costs and expenses		
Lease operating expenses	703	624
Transportation costs	161	141
Production taxes	166	106
Marketing and midstream operating costs and expenses	901	626
Depreciation, depletion and amortization of property and equipment	1,423	1,420
Accretion of asset retirement obligation	28	—
General and administrative expenses	254	230
Reduction of carrying value of oil and gas properties	—	727
Total production and operating costs and expenses	3,636	3,874
Earnings from operations	2,313	132
Other income (expenses)		
Interest expense	(393)	(428)
Dividends on subsidiary's preferred stock	(1)	(3)
Effects of changes in foreign currency exchange rates	52	1
Change in fair value of financial instruments	8	28
Other income	30	23
Net other expenses	(304)	(379)
Earnings (loss) from continuing operations before income tax expense and cumulative effect of change in accounting principle	2,009	(247)
Income tax expense (benefit)		
Current	190	146
Deferred	524	(310)
Total income tax expense (benefit)	714	(164)
Earnings (loss) from continuing operations before cumulative effect of change in accounting principle	1,295	(83)
Discontinued operations		
Results of discontinued operations before income taxes	—	64
Total income tax expense	—	8
Net results of discontinued operations	—	56
Earnings (loss) before cumulative effect of change in accounting principle	1,295	(27)
Cumulative effect of change in accounting principle, net of income tax expense of $19 million	29	—
Net earnings (loss)	1,324	(27)
Preferred stock dividends	7	7
Net earnings (loss) applicable to common stockholders	$1,317	$ (34)

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

	Pro Forma Information Nine Months Ended September 30,	
	2003	2002
	(In millions, except per share amounts and production volumes)	
Basic earnings (loss) per share:		
Earnings (loss) from continuing operations	$5.62	$(0.41)
Net results of discontinued operations	—	0.25
Cumulative effect of change in accounting principle	0.07	—
Net earnings (loss) applicable to common stockholders	$5.69	$(0.16)
Diluted earnings (loss) per share:		
Earnings (loss) from continuing operations	$5.46	$(0.41)
Net results of discontinued operations	—	0.25
Cumulative effect of change in accounting principle	0.06	—
Net earnings (loss) applicable to common stockholders	$5.52	$(0.16)
Weighted average common shares outstanding — basic	231	230
Weighted average common shares outstanding — diluted	240	234
Production volumes:		
Oil (MMBbls)	52	53
Gas (Bcf)	681	703
NGLs (MMBbls)	17	17
MMBoe	182	188

3. Debt

Credit Facilities

Devon has $1 billion of unsecured long-term credit facilities (the “Credit Facilities”). The Credit Facilities include a U.S. facility of $725 million (the “U.S. Facility”) and a Canadian facility of $275 million (the “Canadian Facility”). The $725 million U.S. Facility consists of a Tranche A facility of $200 million and a Tranche B facility of $525 million.

The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until June 2, 2004 (the “Tranche B Revolving Period”). Devon may request that the Tranche B Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Tranche B Revolving Period. On June 2, 2004, at the end of the Tranche B Revolving Period, Devon may convert the then outstanding balance under the Tranche B facility to a one-year term loan by paying the Agent a fee of 25 basis points. The applicable borrowing rate would be at LIBOR plus 112.5 basis points. On September 30, 2003, there were no borrowings outstanding under the $725 million U.S. Facility. The available capacity under the U.S. Facility as of September 30, 2003, net of outstanding letters of credit, was approximately $590 million.

Devon may borrow funds under the $275 million Canadian Facility until June 2, 2004 (the “Canadian Facility Revolving Period”). Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility Revolving Period is payable in semiannual installments of 2.5% each for the following five years, with the final installment due five years and one day following the end of the Canadian Facility Revolving Period. On September 30, 2003, there were no borrowings under the $275 million Canadian facility. The available capacity

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

under the Canadian Facility as of September 30, 2003, net of outstanding letters of credit, was approximately $202 million.

Under the terms of the Credit Facilities, Devon has the right to reallocate up to $100 million of the unused Tranche B facility maximum credit amount to the Canadian Facility. Conversely, Devon also has the right to reallocate up to $100 million of unused Canadian Facility maximum credit amount to the Tranche B Facility.

Amounts borrowed under the Credit Facilities bear interest at various fixed rate options that Devon may elect for periods up to six months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Credit Facilities provide for an annual facility fee of $1.4 million that is payable quarterly in arrears.

The agreements governing the Credit Facilities contain certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio of 65% as defined in the agreements. As of September 30, 2003, Devon’s debt-to-capitalization ratio as defined in the agreements was 42.8%.

Debt Securities

On August 4, 2003, Devon issued $500 million of 2.75% notes due August 1, 2006. The debt securities are unsecured obligations of Devon and are redeemable at the option of Devon, in whole or in part, at any time at a redemption price equal to the greater of 100% of the principal amount of the notes outstanding plus accrued and unpaid interest to the redemption date or the sum of the present values of the remaining scheduled payments of principal and interest thereon (exclusive of interest accrued to the date of redemption) from the redemption date to the maturity date plus accrued and unpaid interest to the redemption date. The proceeds from the issuance of these debt securities, net of discounts and issuance costs, of $498 million were used to repay amounts outstanding under the $3 billion senior unsecured term loan credit facility.

In conjunction with the notes offering, Devon also entered into a $500 million interest rate swap. The swap will effectively convert Devon’s interest rate on the $500 million of newly issued debt from the fixed rate of 2.75% to a floating rate of LIBOR less 26.8 basis points.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Ocean Debt

In connection with the Ocean merger, Devon assumed $1.8 billion of debt. A summary of this debt is as follows:

	Fair Value of Debt Assumed as of April 25, 2003
	(In millions)
Revolving credit line	$ 160
Note payable	50
Senior notes and senior subordinated notes:	
7.875% due August 2003 (principal of $100 million)	102
7.625% due July 2005 (principal of $125 million)	139
7.500% due September 2007 (principal of $150 million)	169
4.375% due October 2007 (principal of $400 million)	410
8 375% due July 2008 (principal of $200 million)	208
7.250% due September 2011 (principal of $350 million)	406
8.250% due July 2018 (principal of $125 million)	147
Other	6
	1,797
Less amount classified as current	361
Long-term debt	$1,436

Change of control provisions required the outstanding borrowings under the credit facility and note payable to be fully paid immediately. Additionally, Devon was required to extend purchase offers for certain senior notes and the senior subordinated notes. As a result of these purchase offers, which expired on June 13, 2003, Devon paid $118 million for the aggregate principal amount tendered. The purchase price for each offer was 101 percent of the principal amount of the notes tendered plus accrued and unpaid interest to and including the purchase date. All notes that were not tendered remain outstanding except as described below.

Included in the $118 million of debt retired pursuant to the purchase offer were $13 million of the 8.375% notes and $57 million of the 7.875% notes. The remaining $195 million of 8.375% notes were called and redeemed on July 1, 2003. Additionally, the remaining $43 million of 7.875% senior notes were paid August 1, 2003, when they were due.

4. Derivative Instruments and Hedging Activities

Devon has periodically entered into oil and gas financial instruments and foreign exchange rate swaps to manage its exposure to oil and gas price volatility. The foreign exchange rate swaps mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on certain Canadian gas revenues that are based on U.S. dollar prices. Devon has also entered into interest rate swaps to manage its exposure to interest rate volatility. The interest rate swaps mitigate either the effects on interest expense for variable-rate debt instruments, or the debt fair values for fixed-rate debt. It is Devon’s policy to only enter into derivative contracts with investment grade rated counterparties deemed by management to be competent and competitive market makers.

The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon.

As of September 30, 2003, $69 million of net deferred losses on derivative instruments in “accumulated other comprehensive income (loss)” are expected to be reclassified to earnings from operations during the next 12 months assuming no change in commodity prices from the September 30, 2003 level. The transactions and events expected to occur over the next 12 months that will necessitate reclassifying these derivatives’ losses to earnings from operations are primarily the production and sale of the hedged oil and gas quantities. The maximum term over which Devon is hedging exposures to the variability of cash flows for commodity price risk is 27 months.

Devon recorded in its statements of operations a loss of $1 million and a gain of $21 million in the third quarter of 2003 and 2002, respectively, and gains of $8 million and $28 million in the nine-month periods ended September 30, 2003 and 2002, respectively, for the change in fair value of derivative instruments that do not qualify for hedge accounting treatment, as well as the ineffectiveness of derivatives that do qualify as hedges.

5. Asset Retirement Obligations

Effective January 1, 2003, Devon adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143) using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is fair value, defined as “the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale.”

The asset retirement cost equal to the fair value of the retirement obligation is capitalized as part of the cost of the related long-lived asset and allocated to expense using a systematic and rational method.

Devon previously estimated costs of dismantlement, removal, site reclamation, and other similar activities in the total costs that are subject to depreciation, depletion, and amortization. However, Devon did not record a separate asset or liability for such amounts. Upon adoption, Devon recorded a cumulative-effect-type adjustment for an increase to net earnings of $16 million net of deferred taxes of $10 million. Additionally, Devon established an asset retirement obligation of $453 million, an increase to property and equipment of $400 million and a decrease in accumulated DD&A of $79 million.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Following is a reconciliation of the asset retirement obligation from December 31, 2002 to September 30, 2003.

	(In millions)
Asset retirement obligation as of December 31, 2002	
Cumulative effect of change in accounting principle	453
Asset retirement obligation assumed from Ocean merger	134
Liabilities incurred	33
Liabilities settled	(26)
Accretion expense	26
Foreign currency translation adjustment	31
Asset retirement obligation as of September 30, 2003	651
Less current portion	32
Asset retirement obligation, long-term	$619

Following is a reconciliation of reported net income and the related earnings per share amounts assuming the provisions of SFAS No. 143 had been adopted as of January 1, 2000.

	For the Year Ended December 31,		
	2002	2001	2000
	(In millions, except per share amounts)		
Net earnings applicable to common stockholders, as reported	$ 94	$ 93	$ 720
Net change in depreciation, depletion and amortization of property and equipment due to adoption of SFAS No. 143	16	30	26
Less accretion of asset retirement obligation	(25)	(15)	(10)
Deferred taxes	4	(6)	(6)
Effect on net earnings	(5)	9	10
Net earnings applicable to common stockholders, as adjusted	$ 89	$ 102	$ 730
Basic earnings per share:			
Net earnings applicable to common stockholders, as reported	$ 0.61	$0.73	$5.66
Effect on net earnings	(0.03)	0.07	0.08
Net earnings applicable to common stockholders, as adjusted	$ 0.58	$0.80	$5.74
Diluted earnings per share:			
Net earnings applicable to common stockholders, as reported	$ 0.61	$0.72	$5.50
Effect on net earnings	(0.03)	0.07	0.08
Net earnings applicable to common stockholders, as adjusted	$ 0.58	$0.79	$5.58

DEVON ENERGY CORPORATION AND SUBSIDIARIES
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	For Three Months Ended September 30,	
	2003	2002
	(In millions, except per share amounts)	
Net earnings applicable to common stockholders, as reported	$ 410	$ 60
Net change in depreciation, depletion and amortization of property and equipment due to adoption of SFAS No. 143	—	4
Less accretion of asset retirement obligation	—	(7)
Deferred taxes	—	1
Effect on net earnings	—	(2)
Net earnings applicable to common stockholders, as adjusted	$ 410	$ 58
Basic earnings per share:		
Net earnings applicable to common stockholders, as reported	$1.76	$ 0.38
Effect on net earnings	—	(0.01)
Net earnings applicable to common stockholders, as adjusted	$1.76	$ 0.37
Diluted earnings per share:		
Net earnings applicable to common stockholders, as reported	$1.71	$ 0.37
Effect on net earnings	—	(0.01)
Net earnings applicable to common stockholders, as adjusted	$1.71	$ 0.36

	For Nine Months Ended September 30,	
	2003	2002
	(In millions, except per share amounts)	
Net earnings applicable to common stockholders, as reported	$1,197	$ 13
Less cumulative effect of change in accounting principle	(16)	—
Net change in depreciation, depletion and amortization of property and equipment due to adoption of SFAS No. 143	—	12
Less accretion of asset retirement obligation	—	(18)
Deferred taxes	—	2
Effect on net earnings	(16)	(4)
Net earnings applicable to common stockholders, as adjusted	$1,181	$ 9
Basic earnings per share:		
Net earnings applicable to common stockholders, as reported	$ 5.97	$ 0.08
Effect on net earnings	(0.08)	(0.02)
Net earnings applicable to common stockholders, as adjusted	$ 5.89	$ 0.06
Diluted earnings per share:		
Net earnings applicable to common stockholders, as reported	$ 5.76	$ 0.08
Effect on net earnings	(0.07)	(0.02)
Net earnings applicable to common stockholders, as adjusted	$ 5.69	$ 0.06

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Following is a summary of the asset retirement obligation assuming the provisions of SFAS No. 143 had been adopted as of January 1, 2000.

	(In millions)
Asset retirement obligation as of:	
January 1, 2000	$163
December 31, 2000	244
December 31, 2001	397
December 31, 2002	453
September 30, 2003	651

6. Earnings Per Share

The following table reconciles the net earnings and common shares outstanding used in the calculations of basic and diluted earnings per share for the three-month periods ended September 30, 2003 and 2002 and the nine-month period ended September 30, 2003. The diluted earnings per share calculation for the nine-month period ended September 30, 2002 produce results that are anti-dilutive as a result of the loss on continuing operations. The diluted calculation for the nine months ended September 30, 2002 increased the net earnings by $5 million and increased the common shares outstanding by 6 million shares. Therefore, the diluted earnings per share amounts for the nine-month period ended September 30, 2002 reported in the accompanying consolidated statements of operations are the same as the basic earnings per share amounts.

	Net Earnings Applicable to Common Stockholders	Common Shares Outstanding	Net Earnings Per Share
		(In millions)	
Three Months Ended September 30, 2003:			
Basic earnings per share	$410	232	$1.76
Dilutive effect of:			
Potential common shares issuable upon conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $1 million)	2	4	
Potential common shares issuable upon conversion of preferred stock of subsidiary	—	1	
Potential common shares issuable upon the exercise of outstanding stock options	—	4	
Diluted earnings per share	$412	241	$1.71
Three Months Ended September 30, 2002:			
Basic earnings per share	$ 60	156	$0.38
Dilutive effect of:			
Potential common shares issuable upon the exercise of outstanding stock options	—	2	
Diluted earnings per share	$ 60	158	$0.37

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	Net Earnings Applicable to Common Stockholders	Common Shares Outstanding	Net Earnings Per Share
	(In millions)		
Nine Months Ended September 30, 2003:			
Basic earnings per share	$1,197	200	$5.97
Dilutive effect of:			
Potential common shares issuable upon conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $3 million)	7	4	
Potential common shares issuable upon conversion of preferred stock of subsidiary	1	1	
Potential common shares issuable upon the exercise of outstanding stock options	—	4	
Diluted earnings per share	$1,205	209	$5.76

The senior convertible debentures were not included in the dilution calculation for the three month period ended September 30, 2002, because the inclusion was anti-dilutive.

Certain options to purchase shares of Devon's common stock have been excluded from the 2003 dilution calculations because the options' exercise price exceeded the average market price of Devon's common stock during the applicable period. The following information relates to these options.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2003	2002	2003	2002
Options excluded from dilution calculation (in millions)	3	3	4	3
Range of exercise prices	$50.29 - $89.66	$44.60 - $89.66	$49.59 - $89.66	$44.85 - $89.66
Weighted average exercise price	$ 58.12	$ 53.89	$ 57.43	$ 53.91

The excluded options for 2003 expire between December 9, 2003 and September 9, 2012.

Devon applies the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations, in accounting for its fixed plan stock options. As such, compensation expense would be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. SFAS No. 123, *Accounting for Stock-Based Compensation*, established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS No. 123, Devon has elected to continue to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS No. 123.

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Had Devon elected the fair value provisions of SFAS No. 123 and recognized compensation expense over the vesting period based on the fair value of the stock options granted as of their grant date, Devon's third quarter and first nine months 2003 and 2002 pro forma net earnings and pro forma net earnings per share would have differed from the amounts actually reported as shown in the following table.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions, except per share amounts)			
Net earnings available to common stockholders, as reported	$ 410	$ 60	$1,197	$ 13
Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(5)	(3)	(15)	(9)
Net earnings available to common stockholders, pro forma	$ 405	$ 57	$1,182	$ 4
Net earnings per share available to common stockholders:				
As reported:				
Basic	$1.76	$0.38	$ 5.97	$0.08
Diluted	$1.71	$0.37	$ 5.76	$0.08
Pro forma:				
Basic	$1.74	$0.36	$ 5.90	$0.02
Diluted	$1.69	$0.35	$ 5.69	$0.02

7. Supplemental Cash Flow Information

Cash payments (refunds) for interest and income taxes in the first nine months of 2003 and 2002 are presented below:

	Nine Months Ended September 30,	
	2003	2002
	(In millions)	
Interest paid	$421	$427
Income taxes paid (refunded)	$ 48	$ (41)

The 2003 Ocean merger and the 2002 Mitchell merger involved non-cash consideration as presented below:

	Ocean Merger	Mitchell Merger
	(In millions)	
Value of common stock issued	$3,546	$1,512
Convertible preferred stock assumed	64	—
Employee stock options assumed	124	27
Liabilities assumed	2,368	824
Deferred tax liability created	829	796
Assets acquired with non-cash consideration	$6,931	$3,159

DEVON ENERGY CORPORATION AND SUBSIDIARIES
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8. Segment Information

Devon manages its business by country. As such, Devon identifies its reporting segments based on geographic areas. Devon has three reporting segments: its operations in the U.S., its operations in Canada and its international operations outside of North America. Substantially all of these segments' operations involve oil and gas producing and marketing and midstream activities. Following is certain financial information regarding Devon's segments. The revenues reported are all from external customers.

	U.S.	Canada	Inter-national	Total
		(In millions)		
As of September 30, 2003:				
Current assets	$ 1,119	$ 535	$ 253	$ 1,907
Property and equipment, net of accumulated depreciation, depletion and amortization	10,564	4,558	2,726	17,848
Investment in ChevronTexaco Corporation common stock, at fair value	507	—	—	507
Goodwill	3,025	2,248	68	5,341
Other assets	325	28	11	364
Total assets	$15,540	$7,369	$3,058	$25,967
Current liabilities	1,307	283	116	1,706
Other liabilities	398	4	2	404
Asset retirement obligation, long-term	379	222	18	619
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	673	—	—	673
Other long-term debt	4,150	3,758	—	7,908
Preferred stock of a subsidiary	55	—	—	55
Deferred revenue	70	—	—	70
Fair value of financial instruments	10	6	—	16
Deferred income taxes	2,244	1,606	476	4,326
Stockholders' equity	6,254	1,490	2,446	10,190
Total liabilities and stockholders' equity	$15,540	$7,369	$3,058	$25,967

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	U.S.	Canada	International	Total
		(In millions)		
Three Months Ended September 30, 2003:				
Revenues				
Oil sales	$ 243	$ 79	$147	$ 469
Gas sales	734	308	7	1,049
Natural gas liquids sales	68	26	1	95
Marketing and midstream revenues	331	4	—	335
Total revenues	1,376	417	155	1,948
Production and operating costs and expenses				
Lease operating expenses	134	83	21	238
Transportation costs	40	16	1	57
Production taxes	51	1	2	54
Marketing and midstream operating costs and expenses	266	2	—	268
Depreciation, depletion and amortization of property and equipment	333	105	70	508
Accretion of asset retirement obligation	6	3	1	10
General and administrative expenses	68	9	2	79
Total production and operating costs and expenses	898	219	97	1,214
Earnings from operations	478	198	58	734
Other income (expenses)				
Interest expense	(49)	(70)	(1)	(120)
Effects of changes in foreign currency exchange rates	—	1	—	1
Change in fair value of financial instruments	(2)	1	—	(1)
Other income	4	(1)	1	4
Net other expenses	(47)	(69)	—	(116)
Earnings from continuing operations before income tax expense	431	129	58	618
Income tax expense (benefit)				
Current	38	(17)	20	41
Deferred	99	61	5	165
Total income tax expense	137	44	25	206
Net earnings	294	85	33	412
Preferred stock dividends	2	—	—	2
Net earnings applicable to common stockholders	$ 292	$ 85	$ 33	$ 410
Capital expenditures	$ 489	$154	$ 62	$ 705

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	U.S.	Canada	International	Total
		(In millions)		
Three Months Ended September 30, 2002:				
Revenues				
Oil sales	$119	$ 83	$ 15	$ 217
Gas sales	328	152	—	480
Natural gas liquids sales	48	21	—	69
Marketing and midstream revenues	262	3	—	265
Total revenues	757	259	15	1,031
Production and operating costs and expenses				
Lease operating expenses	85	64	3	152
Transportation costs	25	14	—	39
Production taxes	23	2	—	25
Marketing and midstream operating costs and expenses	211	1	—	212
Depreciation, depletion and amortization of property and equipment	200	82	—	282
General and administrative expenses	36	9	2	47
Total production and operating costs and expenses	580	172	5	757
Earnings from operations	177	87	10	274
Other income (expenses)				
Interest expense	(57)	(72)	(1)	(130)
Effects of changes in foreign currency exchange rates	—	(17)	1	(17)
Change in fair value of financial instruments	27	(6)	—	21
Other income	(2)	3	—	2
Net other expenses	(32)	(92)	—	(124)
Earnings (loss) from continuing operations before income tax expense	145	(5)	10	150
Income tax expense				
Current	32	2	2	36
Deferred	1	—	1	2
Total income tax expense	33	2	3	38
Earnings (loss) from continuing operations	112	(7)	7	112
Discontinued operations				
Results of discontinued operations before income taxes	—	—	(48)	(48)
Total income tax expense	—	—	2	2
Net results of discontinued operations	—	—	(50)	(50)
Net earnings (loss)	112	(7)	(43)	62
Preferred stock dividends	2	—	—	2
Net earnings (loss) applicable to common stockholders	$110	$ (7)	$(43)	$ 60
Capital expenditures	$325	$129	$ 21	$ 475

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
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	U.S.	Canada	International	Total
		(In millions)		
Nine Months Ended September 30, 2003:				
Revenues				
Oil sales	$ 625	$ 240	$239	$1,104
Gas sales	1,983	936	11	2,930
Natural gas liquids sales	206	86	2	294
Marketing and midstream revenues	1,092	12	—	1,104
Total revenues	3,906	1,274	252	5,432
Production and operating costs and expenses				
Lease operating expenses	349	235	42	626
Transportation costs	100	47	2	149
Production taxes	146	2	4	152
Marketing and midstream operating costs and expenses	895	6	—	901
Depreciation, depletion and amortization of property and equipment	835	281	115	1,231
Accretion of asset retirement obligation	16	9	1	26
General and administrative expenses	182	30	9	221
Expenses related to mergers	7	—	—	7
Total production and operating costs and expenses	2,530	610	173	3,313
Earnings from operations	1,376	664	79	2,119
Other income (expenses)				
Interest expense	(159)	(214)	(7)	(380)
Dividends on subsidiary’s preferred stock	(1)	—	—	(1)
Effects of changes in foreign currency exchange rates	—	51	1	52
Change in fair value of financial instruments	9	(1)	—	8
Other income	18	4	7	29
Net other income (expenses)	(133)	(160)	1	(292)
Earnings from continuing operations before income tax expense and cumulative effect of change in accounting principle	1,243	504	80	1,827
Income tax expense (benefit)				
Current	141	(6)	30	165
Deferred	254	214	6	474
Total income tax expense	395	208	36	639
Earnings from continuing operations before cumulative effect of change in accounting principle	848	296	44	1,188
Cumulative effect of change in accounting principle	11	5	—	16
Net earnings	859	301	44	1,204
Preferred stock dividends	7	—	—	7
Net earnings applicable to common stockholders	$ 852	$ 301	$ 44	$1,197
Capital expenditures	$1,158	$ 502	$145	$1,805

DEVON ENERGY CORPORATION AND SUBSIDIARIES
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	U.S.	Canada	International	Total
		(In millions)		
Nine Months Ended September 30, 2002:				
Revenues				
Oil sales	$ 397	$ 255	$35	$ 687
Gas sales	1,008	500	—	1,508
Natural gas liquids sales	134	62	—	196
Marketing and midstream revenues	682	10	—	692
Total revenues	2,221	827	35	3,083
Production and operating costs and expenses				
Lease operating expenses	272	187	9	468
Transportation costs	73	42	—	115
Production taxes	75	5	—	80
Marketing and midstream operating costs and expenses	554	5	—	559
Depreciation, depletion and amortization of property and equipment	624	290	2	916
General and administrative expenses	113	27	11	151
Reduction of carrying value of oil and gas properties	—	651	—	651
Total production and operating costs and expenses	1,711	1,207	22	2,940
Earnings (loss) from operations	510	(380)	13	143
Other income (expenses)				
Interest expense	(179)	(220)	(3)	(402)
Change in fair value of financial instruments	32	(4)	—	28
Other income	13	5	5	23
Net other income (expenses)	(134)	(219)	2	(351)
Earnings (loss) from continuing operations before income tax expense	376	(599)	15	(208)
Income tax expense (benefit)				
Current	106	11	5	122
Deferred	(41)	(256)	3	(294)
Total income tax expense (benefit)	65	(245)	8	(172)
Earnings (loss) from continuing operations	311	(354)	7	(36)
Discontinued operations				
Results of discontinued operations before income taxes	—	—	64	64
Total income tax expense	—	—	8	8
Net results of discontinued operations	—	—	56	56
Net earnings (loss)	311	(354)	63	20
Preferred stock dividends	7	—	—	7
Net earnings (loss) applicable to common stockholders	$ 304	$ (354)	$63	$ 13
Capital expenditures, including acquisitions of businesses	$2,549	$ 425	$64	$3,038

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9. Commitments and Contingencies

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon’s estimates of the outcomes of such matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon’s financial position or results of operations after consideration of recorded accruals although actual amounts could differ from management’s estimate.

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”) and similar state statutes. In response to liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no material claims for possible recovery from third party insurers or other parties related to environmental costs have been recognized in Devon’s consolidated financial statements. Devon adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates must be adjusted to reflect new information.

Certain of Devon’s subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties (“PRPs”) under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of September 30, 2003, Devon’s consolidated balance sheet included $7 million of non-current accrued liabilities, reflected in “Other liabilities,” related to these and other environmental remediation liabilities. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon’s conclusion is based in large part on (i) Devon’s participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a *de minimis* PRP, and (iii) the availability of other defenses to liability. As a result, Devon’s monetary exposure is not expected to be material.

Royalty Matters

Numerous gas producers and related parties, including Devon, have been named in various lawsuits alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The principal suit in which Devon is a defendant is *United States ex rel. Wright v. Chevron USA, Inc. et al* . (the “ *Wright* case”). The suit was originally filed in August 1996 in the United States District Court for the Eastern District of Texas, but was consolidated in October 2000 with the other suits for pre-trial proceedings in the United States District Court for the District of Wyoming. On July 10, 2003, the District of Wyoming remanded the *Wright* case back to the Eastern District of Texas to resume proceedings. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suit, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this lawsuit and no liability has been recorded in connection therewith.

Devon is a defendant in certain private royalty owner litigation filed in Wyoming regarding deductibility of certain post production costs from royalties payable by Devon. The plaintiffs in these lawsuits propose to expand them into county or state-wide class actions relating specifically to transportation and related costs associated with Devon's Wyoming gas production. A significant portion of such production is, or will be, transported through facilities owned by Thunder Creek Gas Services, L.L.C., of which Devon owns a 75% interest. Devon believes that it has acted reasonably and paid royalties in good faith and in accordance with its obligations under its oil and gas leases and applicable law, and Devon does not believe that it is subject to material exposure in association with this litigation.

Other Matters

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon's knowledge as of the date of this report, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion addresses material changes in results of operations for the three-month and nine-month periods ended September 30, 2003, compared to the three-month and nine-month periods ended September 30, 2002, and in financial condition since December 31, 2002. It is presumed that readers have read or have access to Devon's 2002 Annual Report on Form 10-K which includes disclosures regarding critical accounting policies as part of Management's Discussion and Analysis of Financial Condition and Results of Operations.

Overview

Net earnings for the third quarter of 2003 were $412 million, or $1.71 per share. This compares to net earnings of $62 million, or $0.37 per share for the third quarter of 2002. Net earnings for the first nine months of 2003 were $1.2 billion, or $5.76 per share. This compares to net earnings of $20 million, or $0.08 per share for the first nine months of 2002. The increases in third quarter and first nine months earnings were due to increases in both production and prices of oil, natural gas and NGLs and the fact that 2002 earnings were adversely impacted by a $371 million after-tax reduction in the carrying value of oil and gas properties.

On April 25, 2003, Devon completed its merger with Ocean Energy Inc. ("Ocean"). In the transaction, Devon issued 0.414 shares of its common stock for each outstanding share of Ocean common stock (or a total of approximately 74 million shares). Also, Devon assumed approximately $1.8 billion of debt from Ocean. This merger had no effect on Devon's financial condition or results of operations prior to April 25, 2003.

Results of Operations

Total revenues increased $917 million, or 89%, in the third quarter of 2003, and $2.3 billion, or 76%, in the first nine months of 2003. This was the result of increases in both production and prices of oil, gas and NGLs as well as an increase in marketing and midstream revenues. The increase in production was primarily the result of the April 2003 Ocean merger and the January 2002 Mitchell merger, partially offset by property divestitures which occurred in 2002.

Oil, gas and NGL revenues were up $847 million, or 111%, for the third quarter of 2003 compared to the third quarter of 2002, and $1.9 billion, or 81%, for the first nine months of 2003 compared to the first nine months of 2002. The three-month and nine-month periods' comparison of production and price changes are shown in the following tables. (Note: Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.)

	Total					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2003	2002	Change [2]	2003	2002	Change [2]
Production						
Oil (MMBbls)	18	9	+104%	42	32	+33%
Gas (Bcf)	234	185	+27%	631	576	+10%
NGLs (MMBbls)	6	5	+15%	16	15	+8%
Oil, Gas and NGLs (MMBoe) [1]	63	45	+41%	163	143	+15%
Average Prices						
Oil (Per Bbl)	$25.19	$23.71	+6%	$25.89	$21.38	+21%
Gas (Per Mcf)	4.47	2.59	+72%	4.64	2.62	+77%
NGLs (Per Bbl)	16.74	14.10	+19%	18.51	13.35	+39%
Oil, Gas and NGLs (Per Boe) [1]	25.44	17.06	+49%	26.44	16.74	+58%
Revenues ($ in millions)						
Oil	$ 469	$ 217	+117%	$1,104	$ 687	+61%
Gas	1,049	480	+119%	2,930	1,508	+94%
NGLs	95	69	+37%	294	196	+50%
Combined	$1,613	$ 766	+111%	$4,328	$2,391	+81%

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Domestic

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2003	2002	Change [2]	2003	2002	Change [2]
Production						
Oil (MMBbls)	9	5	+74%	22	18	+21%
Gas (Bcf)	162	118	+38%	428	365	+17%
NGLs (MMBbls)	5	4	+19%	12	11	+14%
Oil, Gas and NGLs (MMBoe) [1]	41	29	+42%	106	90	+18%
Average Prices						
Oil (Per Bbl)	$27.26	$23.48	+16%	$27.98	$21.55	+30%
Gas (Per Mcf)	4.52	2.77	+63%	4.63	2.76	+68%
NGLs (Per Bbl)	15.30	12.98	+18%	17.09	12.68	+35%
Oil, Gas and NGLs (Per Boe) [1]	25.84	17.39	+49%	26.60	17.13	+55%
Revenues ($ in millions)						
Oil	$ 243	$ 119	+102%	$ 625	$ 397	+57%
Gas	734	328	+124%	1,983	1,008	+97%
NGLs	68	48	+41%	206	134	+54%
Combined	$1,045	$ 495	+111%	$2,814	$1,539	+83%

Canada

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2003	2002	Change [2]	2003	2002	Change [2]
Production						
Oil (MMBbls)	3	3	0%	10	12	-17%
Gas (Bcf)	70	67	+5%	200	211	-5%
NGLs (MMBbls)	1	1	-3%	4	4	-10%
Oil, Gas and NGLs (MMBoe) [1]	16	15	+3%	47	51	-9%
Average Prices						
Oil (Per Bbl)	$22.94	$24.07	-5%	$23.89	$20.98	+14%
Gas (Per Mcf)	4.39	2.28	+93%	4.69	2.37	+98%
NGLs (Per Bbl)	21.94	17.54	+25%	23.11	15.06	+53%
Oil, Gas and NGLs (Per Boe) [1]	25.31	16.22	+56%	26.83	15.89	+69%
Revenues ($ in millions)						
Oil	$ 79	$ 83	-4%	$ 240	$ 255	-6%
Gas	308	152	+102%	936	500	+87%
NGLs	26	21	+21%	86	62	+38%
Combined	$ 413	$ 256	+61%	$1,262	$ 817	+54%

	International					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2003	2002	Change [2]	2003	2002	Change [2]
Production						
Oil (MMBbls)	6	1	N/M	10	2	N/M
Gas (Bcf)	2	—	N/M	3	—	N/M
NGLs (MMBbls)	—	—	N/M	—	—	N/M
Oil, Gas and NGLs (MMBoe) [1]	6	1	N/M	10	2	N/M
Average Prices						
Oil (Per Bbl)	$23.49	$23.62	-1%	$23.30	$22.56	+3%
Gas (Per Mcf)	3.57	—	N/M	3.52	—	N/M
NGLs (Per Bbl)	21.15	—	N/M	21.19	—	N/M
Oil, Gas and NGLs (Per Boe) [1]	23.37	23.62	-1%	23.18	22.56	+3%
Revenues ($ in millions)						
Oil	$ 147	$ 15	N/M	$ 239	$ 35	N/M
Gas	7	—	N/M	11	—	N/M
NGLs	1	—	N/M	2	—	N/M
Combined	$ 155	$ 15	N/M	$ 252	$ 35	N/M

1 Gas volumes are converted to Boe or MMBoe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of natural gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices. NGL volumes are converted to Boe on a one-to-one basis with oil. The respective prices of oil, gas and NGLs are affected by market and other factors in addition to relative energy content.

2 All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included in this table.

N/M Not meaningful.

The average sales prices per unit of production shown in the preceding tables include the effect of Devon's hedging activities. Following is a comparison of Devon's average sales prices with and without the effect of hedges for the three-month and nine-month periods ended September 30, 2003 and 2002.

	With Hedges		Without Hedges	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2003	2002	2003	2002
Oil (per Bbl)	$25.19	$23.71	$27.17	$24.49
Gas (per Mcf)	$ 4.47	$ 2.59	$ 4.61	$ 2.51
NGLs (per Bbl)	$16.74	$14.10	$16.74	$14.10
Oil, Gas and NGLs (per Boe)	$25.44	$17.06	$26.53	$16.84

	With Hedges		Without Hedges	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Oil (per Bbl)	$25.89	$21.38	$27.67	$21.81
Gas (per Mcf)	$ 4.64	$ 2.62	$ 5.01	$ 2.60
NGLs (per Bbl)	$18.51	$13.35	$18.51	$13.35
Oil, Gas and NGLs (per Boe)	$26.44	$16.74	$28.28	$16.70

Oil Revenues. Oil revenues increased $252 million, or 117%, in the third quarter of 2003. An increase in 2003's production of 9 million barrels, or 104%, caused oil revenues to increase by $226 million. The April 2003 Ocean merger accounted for 9 million barrels of increased production. Oil revenues increased $26 million due to a $1.48 increase in the average price of oil.

Oil revenues increased $417 million, or 61%, in the first nine months of 2003. An increase in production of 10 million barrels, or 33%, caused oil revenues to increase by $225 million. The April 2003 Ocean merger accounted for 15 million barrels of increased production, partially offset by production lost from the 2002 property divestitures of 5 million barrels. Oil revenues increased $192 million due to a $4.51 increase in the average price of oil.

Gas Revenues. Gas revenues increased $569 million, or 119%, in the third quarter of 2003. An increase in production of 49 Bcf, or 27%, caused gas revenues to increase by $129 million. The April 2003 Ocean merger accounted for 41 Bcf of increased production, partially offset by production lost from the 2002 property divestitures of 3 Bcf. The remaining production increase was primarily related to new drilling and development in the Barnett Shale properties acquired in the January 2002 Mitchell merger as well as new drilling and development in Canada. Gas revenues increased $440 million due to a $1.88 increase in the average price of gas.

Gas revenues increased $1.4 billion, or 94%, in the first nine months of 2003. A $2.02 per Mcf increase in the average gas price in the first nine months of 2003 caused revenues to increase $1.27 billion. An increase in production of 55 Bcf, or 10%, caused gas revenues to increase by $144 million. The April 2003 Ocean merger and January 2002 Mitchell acquisition accounted for 71 Bcf and 11 Bcf of increased production, respectively, partially offset by production lost from the 2002 property divestitures of 35 Bcf. The remaining production increase was primarily related to new drilling and development in the Barnett Shale properties.

NGL Revenues. NGL revenues increased $26 million in the third quarter of 2003. A $2.64 per barrel increase in the average NGL price in the third quarter of 2003 increased NGL revenues by $15 million. An increase in production of 1 million barrels, or 15%, caused NGL revenues to increase by $11 million.

NGL revenues increased $98 million in the first nine months of 2003. A $5.16 per barrel increase in the average NGL price in the first nine months of 2003 caused revenues to increase $82 million. An increase in production of 1 million barrels, or 8%, caused NGL revenues to increase by $16 million

The increased production in both the three- and nine-month periods was due in part to the April 2003 Ocean merger and in part to new drilling and development in the Barnett Shale properties.

Marketing and Midstream Revenues. Marketing and midstream revenues increased $70 million, or 27%, in the third quarter of 2003, which was primarily the result of an increase in gas and NGL prices. Third-party processed NGL volumes remained relatively steady, as the net effect of a decline in volumes due to the disposition of certain processing plants was offset by an increase in volumes from new drilling and development primarily in the Barnett Shale.

Marketing and midstream revenues increased $412 million, or 60%, in the first nine months of 2003. Of this total increase, approximately $366 million was the result of an increase in gas and NGL prices. An increase in third-party processed NGL volumes caused the remaining increase in first nine months 2003 revenues. The increase in volumes was primarily related to new drilling and development primarily in the Barnett Shale and an additional 24 days of production in 2003 due to the timing of the January 2002 Mitchell merger, partially offset by volumes lost as a result of processing plant dispositions.

Oil, Gas and NGL Production and Operating Expenses. The components of oil, gas and NGL production and operating expenses are set forth in the following tables.

	Total					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2003	2002	Change [1]	2003	2002	Change [1]
Expenses ($ in Millions)						
Lease operating expenses	$ 238	$ 152	+57%	$ 626	$ 468	+34%
Transportation costs	57	39	+44%	149	115	+30%
Production taxes	54	25	+123%	152	80	+91%
Total production and operating expenses	$ 349	$ 216	+62%	$ 927	$ 663	+40%
Expenses Per Boe						
Lease operating expenses	$3.76	$3.38	+11%	$3.83	$3.28	+17%
Transportation costs	0.90	0.88	+2%	0.91	0.80	+13%
Production taxes	0.86	0.55	+58%	0.93	0.56	+66%
Total production and operating expenses	$5.52	$4.81	+15%	$5.67	$4.64	+22%

1 All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included in this table.

Lease operating expenses increased $86 million in the third quarter of 2003. The April 2003 Ocean merger accounted for $61 million of the increase. The historical Devon lease operating expenses increased $23 million, due to an increase in well workover expenses and increased power, fuel, casualty insurance and repairs and maintenance costs. Additionally, changes in the Canadian-to-U.S. dollar exchange rate resulted in a $10 million increase in costs. These increases were partially offset by a decrease of $8 million due to the 2002 property divestitures.

Lease operating expenses increased $158 million in the first nine months of 2003. The April 2003 Ocean merger accounted for $111 million of the increase. The historical Devon lease operating expenses increased $86 million, due to an increase in well workover expenses and increased power, fuel, casualty insurance and repairs and maintenance costs. Additionally, changes in the Canadian-to-U.S. dollar exchange rate resulted in a $21 million increase in costs. These increases were partially offset by a decrease of $60 million due to the 2002 property divestitures.

Transportation costs increased $18 million and $34 million in the third quarter and the first nine months of 2003, respectively. The April 2003 Ocean merger accounted for $11 million and $20 million of the increase in each period, respectively. The remainder of the increase was due primarily to an increase in gas production.

Production taxes increased $29 million in third quarter of 2003 and $72 million in the first nine months of 2003. The majority of Devon's production taxes are assessed on its onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. Therefore, the 111% and 83% increase in domestic oil, gas and NGL revenues in the third quarter and first-nine months of 2003, respectively, were the primary causes of the production tax increase.

Marketing and Midstream Operating Costs and Expenses. Marketing and midstream operating costs and expenses, increased $56 million, or 27%, in the third quarter of 2003, which was primarily the result of an increase in prices paid for gas and NGLs. Third-party processed NGL volumes remained relatively steady, as the net effect of a decline in volumes from the disposition of certain processing plants was offset by an increase in volumes from new drilling and development primarily in the Barnett Shale.

Marketing and midstream operating costs and expenses increased $342 million, or 61%, in the first nine months of 2003. Of this total increase, $322 million was the result of an increase in prices paid for gas and NGLs. An increase in third-party processed NGL volumes caused the remaining increase in first nine months 2003 revenues. The increase in volumes was primarily related to new drilling and development primarily in the Barnett Shale and an additional 24 days of production in 2003 due to the timing of the January 2002 Mitchell merger. These increases were partially offset by volumes lost as a result of processing plant dispositions.

Depreciation, Depletion and Amortization Expenses ("DD&A"). Oil and gas property related DD&A increased $222 million, or 87%, from $254 million in the third quarter of 2002 to $476 million in the third quarter of 2003. Oil and gas property related DD&A expense increased $106 million due to the 41% increase in combined oil, gas and NGLs production in 2003. Additionally, an increase in the combined U.S., Canadian and international DD&A rate from $5.68 per Boe in 2002 to $7.51 per Boe in 2003 caused oil and gas property related DD&A to increase by $116 million. The increase in the DD&A rate is primarily related to the April 2003 Ocean merger.

Oil and gas property related DD&A increased $299 million, or 36%, from $840 million in the first nine months of 2002 to $1.1 billion in the first nine months of 2003. Oil and gas property related DD&A expense increased $123 million due to the 15% increase in combined oil, gas and NGLs production in 2003. Additionally, an increase in the combined U.S., Canadian and international DD&A rate from $5.88 per Boe in 2002 to $6.96 per Boe in 2003 caused oil and gas property related DD&A to increase by $176 million. The increase in the DD&A rate is primarily related to the April 2003 Ocean merger.

Non-oil and gas property DD&A expense increased $4 million from $28 million in the third quarter of 2002 compared to $32 million in the third quarter of 2003. Depreciation of equipment acquired in the April 2003 Ocean merger accounted for the increase. Non-oil and gas property DD&A expense increased $16 million from $76 million in the first nine months of 2002 compared to $92 million in the first nine months of 2003. Depreciation of equipment acquired in the April 2003 Ocean merger and marketing and midstream assets acquired in the January 2002 Mitchell merger accounted for the increase.

Accretion of Asset Retirement Liability. Effective January 1, 2003, Devon adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143) using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is fair value, defined as “the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale.”

The asset retirement cost equal to the fair value of the retirement obligation is capitalized as part of the cost of the related long-lived asset and allocated to expense using a systematic and rational method.

As required by SFAS No. 143, Devon recorded $10 million and $26 million of accretion expense during the third quarter and first nine months of 2003, respectively.

General and Administrative Expenses (“G&A”). Devon’s net G&A consists of three primary components. The largest of these components is the gross amount of expenses incurred for personnel costs, office expenses, professional fees and other G&A items. The gross amount of these expenses is partially reduced by two offsetting components. One is the amount of G&A capitalized pursuant to the full-cost method of accounting. The other is the amount of G&A reimbursed by working interest owners of properties for which Devon serves as the operator. These reimbursements are received during both the drilling and operational stages of a property’s life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&A in the consolidated statements of operations. The following table is a summary of G&A expenses by component for the third quarter and first nine months of 2003 and 2002.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
		(In millions)		
Gross G&A	$141	$ 91	$376	$281
Capitalized G&A	(41)	(26)	(98)	(75)
Reimbursed G&A	(21)	(18)	(57)	(55)
Net G&A	$ 79	$ 47	$221	$151

Net G&A increased $32 million and $70 million, or 68% and 46%, in the third quarter and first nine months of 2003 compared to the same periods of 2002, respectively. Gross G&A increased $50 million and $95 million, or 55% and 35%, in the third quarter and first nine months of 2003 compared to the same periods of 2002, respectively. The increase in gross expenses in both periods of 2003 was primarily related to the increased activities resulting from the April 2003 Ocean merger and costs incurred to close Devon’s office in The Woodlands, Texas. The gross costs also included additional costs related to a change in the value of investments in certain compensation plans.

The increases in capitalized G&A of $15 million and $23 million in the third quarter and first nine months of 2003, respectively, primarily related to the April 2003 Ocean merger. Reimbursed G&A increased $3 million and $2 million in the third quarter and first nine months of 2003, respectively. Changes in the reimbursed amounts were primarily related to the April 2003 Ocean merger, partially offset by a decline in reimbursements related to the 2002 property divestitures.

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 "costs 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. Therefore, the ceiling limitation is not necessarily indicative of the properties' fair value. 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 writedown otherwise indicated at the end of the quarter is not required to be recorded. A writedown 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 June 30, 2002, Devon's Canadian costs to be recovered exceeded the related ceiling value by $371 million. This after-tax amount resulted in a pre-tax reduction of the carrying value of Devon's Canadian oil and gas properties of $651 million in June 2002. This reduction was the result of a sharp drop in Canadian gas prices during the last half of June 2002. The June 30, 2002 reference prices used in the Canadian ceiling calculation, expressed in Canadian dollars, were a NYMEX price of C$40.79 per barrel of oil and an AECO price of C$2.17 per Mcf. The cash market prices of natural gas increased during the month of July 2002 prior to Devon's release of its second quarter results, but the increase was not sufficient to offset the entire reduction calculated as of June 30, 2002.

Interest Expense. Interest expense decreased $10 million, or 8%, in the third quarter of 2003. The average debt balance increased from $7.9 billion in third quarter of 2002 to $9.2 billion in the 2003 quarter, causing interest expense to increase $18 million. The average interest rate on outstanding debt decreased from 6.2% in the third quarter of 2002 to 5.9% in the third quarter of 2003, causing interest expense to decrease $7 million. Other items included in interest expense that are not related to the debt balance outstanding were $21 million lower in the third quarter of 2003. Of this decrease, $18 million related to the capitalization of interest. The increase in interest capitalized was primarily related to additional unproved properties acquired from the April 2003 Ocean merger.

Interest expense decreased $22 million, or 5%, in the first nine months of 2003. The average debt balance increased from $8.4 billion in the first nine months of 2002 to $8.8 billion in the first nine months of 2003, causing interest expense to increase $19 million. The average interest rate on outstanding debt was 6.0% in both periods. Other items included in interest expense that are not related to the debt balance outstanding were $41 million lower in the third quarter of 2003. Of this decrease, $29 million related to the capitalization of interest and $8 million related to the loss on the early extinguishment of 8.75% senior notes in 2002.

The following schedule includes the components of interest expense for the third quarter and first nine months of 2003 and 2002.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(In millions)			
Interest based on debt outstanding	$135	$124	$395	$376
Amortization of discounts/premiums	(1)	3	2	9
Facility and agency fees	—	1	1	1
Amortization of capitalized loan costs	3	2	10	6
Capitalized interest	(19)	(1)	(32)	(3)
Loss on early debt retirement	—	—	—	8
Other	2	1	4	5
Total interest expense	$120	$130	$380	$402

Effects of Changes in Foreign Currency Exchange Rates. Devon's Canadian subsidiary has certain fixed-rate senior notes which are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar while the notes are outstanding increase or decrease the expected amount of Canadian dollars eventually required to repay the notes. In addition, Devon's Canadian subsidiary has cash and other working capital amounts denominated in U.S. dollars which also fluctuate in value with changes in the exchange rate. Such changes in the Canadian dollar equivalent balance of the debt and working capital balances are required to be included in determining net earnings for the period in which the exchange rate changes. The increases in the Canadian-to-U.S. dollar exchange rates from $0.6331 at December 31, 2002 and $0.7378 at June 30, 2003 to $0.7405 at September 30, 2003 resulted in a $1 million gain and $51 million gain in the third quarter and first nine months of 2003, respectively. The changes in the Canadian-to-U.S. dollar exchange rates from $0.6279 at December 31, 2001 and $0.6585 at June 30, 2002 to $0.6306 at September 30, 2002 resulted in a $17 million loss in the third quarter, which offset prior gains of $17 million during the first six months of 2002.

Income Taxes. During interim periods, income tax expense is based on the estimated effective income tax rate that is expected for the entire fiscal year. The estimated effective tax rate in the third quarter of 2003 was 33% compared to 25% in the third quarter of 2002. The estimated effective tax rate was an expense of 35% in the first nine months of 2003 compared to a benefit of 82% in the first nine months of 2002. Excluding the effect of the 2002 reduction of carrying value of Canadian oil and gas properties, the effective tax rate was 24% in the first nine months of 2002.

The 2002 rate, excluding the Canadian writedown, was lower than the statutory federal tax rate primarily due to the tax benefits of certain foreign deductions.

Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), requires that the tax benefit of available tax carryforwards be recorded as an asset to the extent that management assesses the utilization of such carryforwards to be "more likely than not". When the future utilization of some portion of the carryforwards is determined not to be "more likely than not", SFAS No. 109 requires that a valuation allowance be provided to reduce the recorded tax benefits from such assets.

Included as deferred tax assets at September 30, 2003, were the tax effects of approximately $1.1 billion of tax related carryforwards. These carryforwards include U.S. federal net operating loss carryforwards, the majority of which do not begin to expire until 2008, U.S. state net operating loss carryforwards which expire primarily between 2003 and 2014, Canadian carryforwards which expire primarily in 2009, International carryforwards which have no expiration and minimum tax credits which have no expiration. Devon expects the tax benefits from the net operating loss carryforwards to be utilized between 2003 and 2010. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by federal tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, Devon's management believes that future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expirations.

Results of Discontinued Operations. Under the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, Devon reclassified its Indonesian, Argentine and Egyptian activities as discontinued operations. The net results of discontinued operations from the third quarter and first nine months 2002 was primarily due to the sale of these operations during 2002.

Cumulative Effect of Change in Accounting Principle. At the time of adoption of SFAS No. 143 Devon recorded a cumulative-effect-type adjustment for a charge to net earnings of $16 million net of deferred taxes of $10 million.

Capital Expenditures, Capital Resources and Liquidity

The following discussion of capital expenditures, capital resources and liquidity should be read in conjunction with the consolidated statements of cash flows included in Part 1, Item 1.

Capital Expenditures. Cash payments for capital expenditures were $1.8 billion for the first nine months of 2003. This total includes $1.7 billion for the acquisition, drilling or development of oil and gas properties. These amounts compare to cash payments for capital expenditures for the first nine months of 2002 of $3.0 billion. This total includes $1.7 billion related to the January 2002 Mitchell merger and $1.2 billion for the acquisition, drilling or development of oil and gas properties.

The April 2003 Ocean merger did not affect cash paid for 2003 capital expenditures because the consideration given was Devon common stock. This differs from the January 2002 Mitchell merger, in which the consideration given was both Devon common stock and cash, and therefore, the Mitchell merger did have an impact on capital expenditures paid in cash.

Other Cash Uses. Devon's common stock dividends were $28 million and $23 million in the first nine months of 2003 and 2002, respectively. Devon also paid $7 million of preferred stock dividends in each of the first nine months of 2003 and 2002.

Capital Resources and Liquidity. Devon's primary source of liquidity has historically been net cash provided by operating activities ("operating cash flow"). This source has been supplemented as needed by accessing credit lines and commercial paper markets and issuing equity securities and long-term debt securities.

Operating Cash Flow

Net cash provided by operating activities ("operating cash flow") continued to be a primary source of capital and liquidity in the first half of 2003. Operating cash flow in the first nine months of 2003 was $2.8 billion, compared to $1.2 billion in the first nine months of 2002. The increase in operating cash flow in the first nine months of 2003 was primarily caused by the increase in revenues, partially offset by increased expenses, as discussed earlier in this section.

Devon's operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic conditions, weather and other substantially variable factors influence market conditions for these products. These factors are beyond Devon's control and are difficult to predict.

To mitigate some of the risk inherent in oil and natural gas prices, Devon has entered into various financial price swaps and collars and fixed-price physical delivery contracts. Additionally, Devon has utilized price collars to set minimum and maximum prices on a portion of its production. The table below provides the future volumes associated with these various arrangements as of October 15, 2003.

	Price Collars	Price Swap Contracts	Fixed-Price Physical Delivery Contracts	Total
Oil production (MMBbls)				
2003	10	3	—	13
2004	28	12	—	40
2005	15	—	—	15
Natural gas production (Bcf)				
2003	77	26	4	107
2004	326	3	16	345
2005	15	3	14	32

In addition to the above quantities, Devon also has fixed-price physical delivery contracts for the years 2006 through 2011, covering Canadian natural gas production ranging from 8 Bcf to 14 Bcf per year. Thereafter, Devon also has Canadian gas volumes subject to fixed-price contracts in the years from 2012 through 2016, but the yearly volumes are less than 1 Bcf.

By removing the price volatility from the above volumes of oil and natural gas production, Devon has mitigated, but not eliminated, the potential negative effect on operating cash flow of declining prices in exchange for limiting the potential benefit from any future oil and gas price increases.

It is Devon's policy to only enter into derivative contracts with investment grade rated counterparties deemed by management as competent and competitive market makers. Devon does not hold or issue derivative instruments for speculative trading purposes.

In December 2002, Devon announced that its capital expenditure budget for the year 2003 was approximately $1.8 billion. This includes capital for all areas, including exploration and development, marketing and midstream operations, capitalized G&A expense, capitalized interest and other areas. As a result of the April 25, 2003 Ocean merger, Devon's expected capital expenditures will be approximately $2.7 billion in 2003. This capital budget represents the largest planned use of available operating cash flow. To a certain degree, the ultimate timing of these capital expenditures is within Devon's control. Therefore, if oil and natural gas prices decline to levels below its acceptable levels, Devon could choose to defer a portion of these planned 2003 capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity. Based upon current oil and gas price expectations for 2003, Devon anticipates that its operating cash flow will exceed its planned capital expenditures and other cash requirements for the year. Devon currently intends to accumulate any excess cash to fund current and future years' debt maturities. Additional alternatives could be considered based upon the actual amount, if any, of such excess cash.

Credit Lines

Other sources of liquidity are Devon's revolving lines of credit (the "Credit Facilities"). The Credit Facilities include a U.S. facility of $725 million (the "U.S. Facility") and a Canadian facility of $275 million (the "Canadian Facility").

Amounts borrowed under the Credit Facilities bear interest at various fixed rate options that Devon may elect for periods up to six months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Credit Facilities provide for an annual facility fee of $1.4 million that is payable quarterly in arrears.

The $725 million U.S. Facility consists of a Tranche A facility of $200 million and a Tranche B facility of $525 million. The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until June 2, 2004 (the "Tranche B Revolving Period"). Devon may request that the Tranche B Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Tranche B Revolving Period. On June 2, 2004, at the end of the Tranche B Revolving Period, Devon may convert the then outstanding balance under the Tranche B facility to a one-year term loan by paying the Agent a fee of 25 basis points. The applicable borrowing rate would be at LIBOR plus 112.5 basis points. On September 30, 2003, there were no borrowings outstanding under the $725 million U.S. Facility. The available capacity under the U.S. Facility as of September 30, 2003, net of outstanding letters of credit, was $590 million.

Devon may borrow funds under the $275 million Canadian Facility until June 2, 2004 (the "Canadian Facility Revolving Period"). Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility Revolving Period is payable in semiannual installments of 2.5% each for the following five years, with the final installment due five years and one day following the end of the Canadian Facility Revolving Period. On September 30, 2003, there were no borrowings under the $275 million Canadian facility. The available capacity under the Canadian Facility as of September 30, 2003, net of outstanding letters of credit, was $202 million.

Under the terms of the Credit Facilities, Devon has the right to reallocate up to $100 million of the unused Tranche B facility maximum credit amount to the Canadian Facility. Conversely, Devon also has the right to reallocate up to $100 million of unused Canadian Facility maximum credit amount to the Tranche B Facility.

Devon also has access to short-term credit under its commercial paper program. Total borrowings under the U.S. Facility and the commercial paper program may not exceed $725 million. Commercial paper debt generally has a maturity of between seven to 90 days, although it can have a maturity of up to 365 days. Devon had no commercial paper debt outstanding at September 30, 2003.

As of September 30, 2003, Devon had $636 million outstanding under its $3 billion senior unsecured term loan credit facility. This credit facility, which was entered into in October 2001, has a term of five years and is due October 15, 2006. This credit facility includes various rate options which can be elected by Devon, including a rate based on LIBOR plus a margin. As of September 30, 2003, the average interest rate on this facility was 2.1%.

On August 4, 2003, Devon issued $500 million of 2.75% notes due August 1, 2006. The debt securities are unsecured obligations of Devon and are redeemable at the option of Devon, in whole or in part, at any time at a redemption price equal to the greater of 100% of the principal amount of the notes outstanding plus accrued and unpaid interest to the redemption date or the sum of the present values of the remaining scheduled payments of principal and interest thereon (exclusive of interest accrued to the date of redemption) from the redemption date to the maturity date plus accrued and unpaid interest to the redemption date. The proceeds from the issuance of these debt securities, net of discounts and issuance costs, of $498 million were used to repay amounts outstanding under the $3 billion senior unsecured term loan credit facility.

In conjunction with the notes offering, Devon also entered into a $500 million interest rate swap. The swap will effectively convert Devon's interest rate on the $500 million of newly issued debt from the fixed rate of 2.75% to a floating rate of LIBOR less 26.8 basis points. The use of the new debt's proceeds to repay amounts outstanding under the term loan credit facility, combined with the interest rate swap, has reduced the effective interest rate on approximately $500 million of floating rate debt by approximately 115 basis points.

Devon's $1 billion revolving credit facilities and its $3 billion senior unsecured term loan credit facility each contain only one material financial covenant. This covenant requires Devon to maintain a ratio of total funded debt to total capitalization of no more than 65%. The credit agreements contain definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in Devon's consolidated financial statements. Per the agreements, total funded debt excludes the debentures that are exchangeable into shares of ChevronTexaco Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments. As of September 30, 2003, Devon's ratio of total funded debt to total capitalization, as defined in its credit agreements, was 42.8%.

Revisions to 2003 Estimates

On May 8, 2003, Devon filed a Form 8-K that provided forward-looking estimates for the full year 2003. Revisions to certain of those previous estimates are provided herein to reflect the actual year-to-date results.

Year 2003 Potential Operating Items

Oil Prices — Floating Devon's 2003 average prices per barrel for each of its areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate crude oil delivered at Cushing, Oklahoma. Included in the table are the actual differentials to NYMEX during the first three quarters of 2003 and the projected differential range for the fourth quarter of 2003.

	Oil Prices Less than NYMEX Price			
	1st Qtr Actual	2nd Qtr Actual	3rd Qtr Actual	4th Qtr Expected Range
United States	($1.52)	($0.82)	($1.36)	($2.10) to ($1.60)
Canada	($5.36)	($4.32)	($5.68)	($7.00) to ($5.75)
International	($3.74)	($5.00)	($4.10)	($5.25) to ($4.00)

Gas Prices — Floating Devon's 2003 average prices per Mcf for each of its areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is determined to be the first-of-month South Louisiana Henry Hub price index as published monthly in *Inside FERC* . Included in the table are the actual differentials to NYMEX during the first three quarters of 2003 and the projected differential range for the fourth quarter of 2003.

	Gas Prices Less than NYMEX Price			
	1st Qtr Actual	2nd Qtr Actual	3rd Qtr Actual	4th Qtr Expected Range
United States	($1.06)	($0.35)	($0.36)	($0.75) to ($0.25)
Canada	($1.09)	($0.43)	($0.34)	($1.10) to ($0.60)
International	—	($1.95)	($1.40)	($2.50) to ($2.00)

Marketing and Midstream Revenues and Expenses Devon's marketing and midstream revenues and expenses are derived primarily from its natural gas processing plants and natural gas transport pipelines. These revenues and expenses vary in response to several factors. The factors include, but are not limited to, changes in production from wells connected to the pipelines and related processing plants, changes in the absolute and relative prices of natural gas and NGLs, provisions of the contract agreements and the amount of repair and workover activity required to maintain anticipated processing levels.

These factors, coupled with uncertainty of future natural gas and NGL prices, increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, Devon estimates that 2003 marketing and midstream revenues will be between $1.44 billion and $1.47 billion and marketing and midstream expenses will be between $1.17 billion and $1.2 billion.

Oil, Gas and NGL Production and Operating Expenses Devon's oil, gas and NGL production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses vary in response to several factors. Among the most significant of these factors are additions to or deletions from Devon's property base, changes in production tax rates, changes in the general price level of services and materials that are used in the operation of the properties and the amount of repair and workover activity required. Oil, natural gas and NGL prices also have an effect on lease operating expenses and impact the economic feasibility of planned workover projects.

Given these uncertainties, Devon estimates that 2003 lease operating expenses will be between $865 million and $885 million, transportation costs will be between $200 million and $210 million, and production taxes will be between 3.2% and 3.5% of consolidated oil, natural gas and NGL revenues, excluding revenues related to hedges upon which production taxes are not incurred.

Depreciation, Depletion and Amortization ("DD&A") The 2003 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2003 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2002 reserve estimates (and its estimates of reserves acquired in April in the Ocean merger) that, based on prior experience, are likely to be made during 2003.

Given these uncertainties, oil and gas property related DD&A expense for 2003 is expected to be between $1.61 billion and $1.65 billion. Additionally, Devon expects its DD&A expense related to non-oil and gas property fixed assets to total between $120 million and $130 million. This range includes $65 million to $70 million related to marketing and midstream assets. Based on these DD&A amounts and the production estimates set forth earlier, Devon expects its consolidated DD&A rate will be between $7.63 per Boe and $7.82 per Boe.

Interest Expense Future interest rates, debt outstanding and oil, natural gas and NGL prices have a significant effect on Devon's interest expense. Devon can only marginally influence the prices it will receive in 2003 from sales of oil, natural gas and NGLs and the resulting cash flow. These factors increase the margin of error inherent in estimating future interest expense. Other factors which affect interest expense, such as the amount and timing of capital expenditures, are within Devon's control.

The interest expense in 2003 related to Devon's fixed-rate debt, including net accretion of related discounts, will be approximately $520 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of Devon's long-term debt. Devon's floating rate debt is discussed in the following paragraphs.

As of September 30, 2003, Devon had $0.6 billion outstanding under its original $3.0 billion amortizing senior unsecured term loan credit facility. This credit facility, which was entered into in October 2001, has a term of five years. This credit facility is non-revolving. The remaining balance outstanding as of September 30, 2003 will mature on October 15, 2006.

This $3 billion facility includes various rate options which can be elected by Devon, including a rate based on LIBOR plus a margin. The margin is based on Devon's debt rating. Based on Devon's current debt rating, the margin is 100 basis points. As of September 30, 2003, the average interest rate on this facility was 2.1%.

Devon's interest expense totals have historically included payments of facility and agency fees, amortization of debt issuance costs, the effect of the interest rate swaps, and other miscellaneous items not related to the debt balances outstanding. Devon expects between $5 million and $15 million of such items to be included in its 2003 interest expense. Also, Devon expects to capitalize between $45 million and $55 million of interest during 2003. Based on the information related to interest expense set forth herein and assuming no material changes in Devon's levels of indebtedness or prevailing interest rates, Devon expects its 2003 interest expense will be between $500 million and $510 million.

Other Revenues Devon's other revenues in 2003 are expected to be between $40 million and $45 million.

Income Taxes On November 7, 2003, the Canadian Government passed legislation reducing the Canadian Federal income tax rate for companies in the natural resource sector. The Canadian Federal tax rate applicable to the resource sector will be reduced from 28% to 21% over a five-year phase-in period commencing January 2003, bringing the income tax rate for the resource sector into line with the rate for other Canadian industry sectors by the beginning of 2007. The effect of this change will result in a non-cash benefit to Devon by lowering 2003 deferred tax expense and the related deferred tax liability. However, the amount of the benefit, which will be recorded in the fourth quarter of 2003, has not yet been determined.

Year 2003 Potential Capital Sources, Uses and Liquidity

Capital Expenditures Though Devon has completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, Devon does not "budget", nor can it reasonably predict, the timing or size of such possible acquisitions, if any.

Devon's capital expenditures budget is based on an expected range of future oil, natural gas and NGL prices as well as the expected costs of the capital additions. Should actual prices received differ materially from Devon's price expectations for its future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2003 capital expenditures. In addition, if the actual costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from Devon's estimates.

Given the limitations discussed, the company expects its 2003 capital expenditures for drilling and development efforts, plus related facilities, to total between $2.3 billion and $2.5 billion. These amounts include between $760 million and $810 million for drilling and facilities costs related to reserves classified as proved as of year-end 2002. In addition, these amounts include between $850 million and $900 million for other low risk/reward projects and between $695 million and $755 million for higher risk/reward projects. Low risk/reward projects include development drilling that does not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Higher risk/reward projects include exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs.

The following table shows expected drilling and facilities expenditures by geographic area.

	Drilling and Production Facilities Expenditures			
	United States	Canada	International	Total
	(In millions)			
Related to Proved Reserves	$ 590 - $610	$ 50 - $60	$120 - $140	$ 760 - $810
Lower Risk/Reward Projects	$ 455 - $475	$350 - $370	$ 45 - $55	$ 850 - $900
Higher Risk/Reward Projects	$ 345 - $365	$255 - $275	$ 95 - $115	$ 695 - $755
Total	$1,390 - $1,450	$655 - $705	$260 - $310	$2,305 - $2,465

In addition to the above expenditures for drilling and development, Devon expects to spend between $50 million to $60 million on its marketing and midstream assets, which include its oil pipelines, gas processing plants, CO_2 removal facilities and gas transport pipelines. Devon also expects to capitalize between $135 million and $145 million of G&A expenses in accordance with the full cost method of accounting. Devon also expects to pay between $40 million and $50 million for plugging and abandonment charges, and to spend between $35 million and $45 million for other non-oil and gas property fixed assets.

Impact of Recently Issued Accounting Standards Not Yet Adopted

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51* , ("Interpretation No. 46") . Interpretation No. 46 requires a company to consolidate a variable interest entity if the company has a variable interest (or combination of variable interests) that will absorb a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual returns if they occur, or both. A direct or indirect ability to make decisions that significantly affect the results of the activities of a variable interest entity is a strong indication that a company has one or both of the characteristics that would require consolidation of the variable interest entity. Interpretation No. 46 also requires additional disclosures regarding variable interest entities. As amended, Interpretation No. 146 will be effective in the first interim or annual period beginning after September 15, 2003, for variable interest entities in which a company holds a variable interest. Devon owns no interests in variable interest entities; therefore, Interpretation No. 46 will not affect Devon's consolidated financial statements.

On May 15, 2003, the FASB issued Statement No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* , ("SFAS No. 150") . SFAS No. 150 requires issuers to classify as liabilities (or assets in some circumstance) three classes of freestanding financial instruments that embody obligations for the issuer. Generally, SFAS No. 150, as amended, is effective for financial instruments entered into or modified after May 31, 2003 and, except for minority interests in limited-life entities, is otherwise effective at the beginning of the first interim period beginning after June 15, 2003. The requirement to fair value the minority interest in limited-life entities has been indefinitely deferred. Devon currently has no financial instruments within the scope of SFAS No. 150, as amended, and there was no effect on Devon's consolidated financial statements upon adoption July 1, 2003.

Change to Critical Accounting Policy

In May 2003, the SEC issued Staff Accounting Bulletin No. 103, *Update of Codification of Staff Accounting Bulletins* , ("SAB No. 103") to comprehensively update the existing codification of all staff accounting bulletins. In SAB No. 103, the SEC provided new guidance regarding the calculation of the "ceiling" or limitation on the amount of properties that can be capitalized on the balance sheet under the full cost method of accounting for oil and gas properties. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. In SAB No. 103, the SEC expressed its view that the use of end-of-period prices, as adjusted for cash flow hedges, represents the best measure of estimated future cash flows used in calculating the ceiling limitation. Therefore, consistent with the guidance in SAB No. 103, Devon now adjusts the end-of-period price by the effect of cash flow hedges.

Drilling and Producing Rights

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141, *Business Combinations* , and SFAS No. 142, *Goodwill and Other Intangible Assets* , ("SFAS No. 142") to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of oil and gas drilling and producing rights as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs and to provide specific footnote disclosures. Current practice for Devon and the industry generally is to present all oil and gas related assets in property and equipment on the balance sheet as prescribed by pre-existing guidance for accounting for oil and gas producing activities.

If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of oil and gas drilling and producing rights as a separate intangible assets line item on the balance sheet, Devon would be required to reclassify the affected costs out of oil and gas properties and into a separate intangible assets line item. Devon's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with Devon's accounting policies as prescribed under the full cost method of accounting for oil and gas properties. Further, Devon does not believe the classification of the costs of rights associated with extracting oil and gas as intangible assets would have any impact on our compliance with covenants under our debt agreements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The information included in "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of Devon's 2002 Annual Report on Form 10-K is incorporated herein by reference. Such information includes a description of Devon's potential exposure to market risks, including commodity price risk, interest rate risk and foreign currency risk. The following information updates Devon's commodity price risk exposure as of October 15, 2003 as well as the interest rate and foreign currency risk exposure as of September 30, 2003 for changes from that disclosed in the 2002 Form 10-K and the May 8, 2003 Current Report on Form 8-K.

Commodity Price Risk

Devon's major market risk exposure is in the pricing applicable to its oil, gas and NGLs production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to its U.S. and Canadian natural gas and NGL production. Pricing for oil, gas and NGL production has been volatile and unpredictable for several years.

Devon periodically enters into financial hedging activities with respect to a portion of its projected oil and natural gas production through various financial transactions which hedge the future prices received. These transactions include financial price swaps whereby Devon will receive a fixed price for its production and pay a variable market price to the contract counterparty, and costless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. These financial hedging activities are intended to support oil and natural gas prices at targeted levels and to manage Devon's exposure to oil and gas price fluctuations. Devon does not hold or issue derivative instruments for speculative trading purposes.

Devon's total hedged positions on future production as of October 15, 2003 are set forth in the following tables.

Price Swaps

Through various price swaps, Devon has fixed the price it will receive on a portion of its oil and natural gas production in 2003 through 2005. The following tables include information on this fixed-price production by area. Where necessary, the gas prices related to these swaps have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the price has also been adjusted for the Btu content of the gas production that has been hedged.

Oil Production

	2003		
Area	**Bbls/Day**	**Price/Bbl**	**Months of Production**
International	35,000	$25.23	Oct - Dec

	2004		
Area	**Bbls/Day**	**Price/Bbl**	**Months of Production**
United States	16,000	$27.05	Jan - Dec
Canada	8,000	$27.26	Jan - Dec
International	10,000	$25.75	Jan - Dec

Gas Production

	2003		
Area	**Mcf/Day**	**Price/Mcf**	**Months of Production**
United States	97,389	$3.21	Oct - Dec
United States	183,604	$4.53	Oct - Dec

	2004		
Area	**Mcf/Day**	**Price/Mcf**	**Months of Production**
United States	8,435	$3.10	Jan - Dec

	2005		
Area	**Mcf/Day**	**Price/Mcf**	**Months of Production**
United States	7,343	$2.97	Jan - Dec

Costless Price Collars

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003, 2004 and 2005 oil production that otherwise is subject to floating prices. The floor and ceiling prices related to domestic and Canadian oil production are based on the NYMEX price. The floor and ceiling prices related to international oil production are based on the Brent price. If the NYMEX or Brent price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's oil revenues for the period. Because

Devon’s oil volumes are often sold at prices that differ from the NYMEX or Brent price due to differing quality (i.e., sweet crude versus sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon’s realized prices for the production volumes related to the collars.

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003, 2004 and 2005 natural gas production that otherwise is subject to floating prices. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon’s gas revenues for the period. Because Devon’s gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of Devon’s realized prices for the production volumes related to the collars.

To simplify presentation, Devon’s costless collars as of October 15, 2003 have been aggregated in the following table according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

The international oil prices shown in the following tables have been adjusted to a NYMEX-based price, using Devon’s estimates of future differentials between NYMEX and the Brent price upon which the collars are based.

The natural gas prices shown in the following tables have been adjusted to a NYMEX-based price, using Devon’s estimates of future differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by *Inside FERC* . The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the *Canadian Gas Price Reporter* .

Oil Production

	2003			
		Weighted Average		
Area (Range of Floor Prices/Ceiling Prices)	**Bbls/Day**	**Floor Price Per Bbl**	**Ceiling Price Per Bbl**	**Months of Production**
United States ($22.00 - $22.75/$27.05 - $28.10)	12,000	$22.25	$27.60	Oct - Dec
United States ($20.00 - $23.50/$28.25 - $30.00)	14,000	$22.13	$28.86	Oct - Dec
United States ($23.50 - $23.50/$28.25 - $30.75)	6,000	$23.50	$29.31	Oct - Dec
Canada ($21.00 - $22.00/$26.60 - $27.50)	10,000	$21.80	$27.11	Oct - Dec
Canada ($20.00 - $22.75/$27.75 - $28.15)	7,000	$21.57	$27.87	Oct - Dec
Canada ($22.75 - $23.50/$28.35 - $29.75)	9,000	$23.31	$29.75	Oct - Dec

Area (Range of Floor Prices/Ceiling Prices)	2004			
		Weighted Average		
	Bbls/Day	Floor Price Per Bbl	Ceiling Price Per Bbl	Months of Production
United States ($20.00 - $21.50/$26.50 - $28.00)	5,000	$20.80	$27.57	Jan - Dec
United States ($20.00 - $22.00/$28.35 - $29.75)	10,000	$21.55	$29.25	Jan - Dec
United States ($22.00 - $22.00/$30.00 - $31.40)	9,000	$22.00	$30.65	Jan - Dec
Canada ($20.00 - $21.50/$26.50 - $27.70)	3,000	$20.50	$27.07	Jan - Dec
Canada ($20.00 - $22.00/$28.00 - $29.20)	5,000	$21.10	$28.69	Jan - Dec
Canada ($22.00 - $22.00/$29.80 - $32.35)	8,000	$22.00	$31.14	Jan - Dec
International ($22.31 - $22.31/$30.11 - $30.76)	12,000	$22.31	$30.51	Jan - Dec
International ($22.31 - $22.31/$30.81 - $31.51)	15,000	$22.31	$31.08	Jan - Dec
International ($22.31 - $22.31/$31.56 - $32.81)	10,000	$22.31	$31.96	Jan - Dec

Area (Range of Floor Prices/Ceiling Prices)	2005			
		Weighted Average		
	Bbls/Day	Floor Price Per Bbl	Ceiling Price Per Bbl	Months of Production
United States ($22.00 - $22.00/$27.50 - $28.75)	19,000	$22.00	$27.65	Jan - Dec
Canada ($22.00 - $22.00/$27.50 - $28.75)	11,000	$22.00	$28.09	Jan - Dec
International ($22.50 - $22.50/$28.20 - $28.75)	10,000	$22.50	$28.49	Jan - Dec

Gas Production

Area (Range of Floor Prices/Ceiling Prices)	2003			
		Weighted Average		
	MMBtu/ Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	Months of Production
United States ($3.00 - $3.28/$4.02 - $4.26)	130,000	$3.12	$4.11	Oct - Dec
United States ($3.29 - $3.52/$4.25 - $4.56)	110,000	$3.40	$4.41	Oct - Dec
United States ($3.25 - $3.28/$4.65 - $4.93)	70,000	$3.27	$4.80	Oct - Dec
United States ($3.75 - $3.75/$5.23 - $5.23)	20,000	$3.75	$5.23	Oct
United States ($3.75 - $3.75/$5.15 - $5.33)	50,000	$3.75	$5.26	Oct - Dec
United States ($3.28 - $3.28/$5.53 - $5.93)	55,000	$3.28	$5.74	Oct - Dec
United States ($3.28 - $3.28/$6.23 - $6.53)	40,000	$3.28	$6.38	Oct - Dec
Canada ($3.55 - $4.00/$4.37 - $5.54)	90,000	$3.62	$4.50	Oct - Dec
Canada ($4.01 - $4.02/$5.97 - $6.76)	40,000	$4.02	$6.35	Oct - Dec
Canada ($3.84 - $4.04/$6.91 - $7.51)	50,000	$3.91	$7.19	Oct - Dec
Canada ($3.73 - $4.04/$7.62 - $8.08)	50,000	$3.94	$7.80	Oct - Dec
Canada ($4.13 - $4.16/$8.20 - $10.25)	60,000	$4.15	$8.87	Oct

Area (Range of Floor Prices/Ceiling Prices)	2004			
		Weighted Average		
	MMBtu/ Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	Months of Production
United States ($3.32 - $3.57/$5.07 - $5.85)	50,000	$3.42	$5.67	Jan - Dec
United States ($3.25 - $4.32/$6.02 - $7.35)	160,000	$3.96	$6.62	Jan - Dec
United States ($3.32 - $4.00/$7.40 - $7.85)	175,000	$3.80	$7.59	Jan - Dec
United States ($3.50 - $4.07/$7.90 - $8.86)	150,000	$3.67	$8.28	Jan - Dec
Canada ($3.97 - $4.07/$6.24 - $6.82)	60,000	$4.05	$6.52	Jan - Dec
Canada ($3.93 - $4.44/$6.92 - $7.65)	140,000	$4.15	$7.25	Jan - Dec
Canada ($3.85 - $4.00/$8.12 - $8.43)	60,000	$3.91	$8.32	Jan - Dec
Canada ($3.83 - $4.11/$8.81 - $9.29)	70,000	$3.93	$9.00	Jan - Dec
Canada ($3.83 - $3.92/$9.55 - $10.16)	25,000	$3.89	$9.99	Jan - Dec

Area (Range of Floor Prices/Ceiling Prices)	2005			
		Weighted Average		
	MMBtu/ Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	Months of Production
United States ($3.50 - $3.50/$7.50 - $7.50)	40,000	$3.50	$7.50	Jan - Dec

Three-Way Collars

Devon assumed a number of oil and gas three-way collars from Ocean. A three-way collar is a combination of options-a sold put, a purchased put and a sold call. The purchased put establishes a floor price, unless the market price falls below the sold put, at which point the floor price would be the index price plus the difference between the purchased put and the sold put strike prices. The sold call establishes a ceiling price.

The prices related to domestic oil production are based on the NYMEX price, and the prices related to international oil production are based on the Brent price. If the NYMEX or Brent price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon’s oil revenues for the period. Because Devon’s oil volumes are often sold at prices that differ from the NYMEX or Brent price due to differing quality (i.e., sweet crude versus sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon’s realized prices for the production volumes related to the collars.

The prices related to natural gas production are based on the NYMEX price. If the NYMEX price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon’s gas revenues for the period. Because Devon’s gas volumes are often sold at prices that differ from the NYMEX price due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of Devon’s realized prices for the production volumes related to the collars.

To simplify presentation, Devon’s three-way collars as of October 15, 2003, have been aggregated in the following tables according to similar sold call prices. The sold call prices shown are weighted averages of the various collars in each aggregated group. The sold put price and the purchased put price are $19.00 per Bbl and $23.00 per Bbl, respectively, for each domestic oil collar. The sold put price and the purchased put price are $21.00 per Bbl and $25.00 per Bbl, respectively, for each international oil collar. The sold put price and the purchased put price are $2.50 per MMBtu and $3.50 per MMBtu, respectively, for each gas collar.

The international oil prices shown in the following tables have been adjusted to a NYMEX-based price, using Devon's estimates of future differentials between NYMEX and the Brent price upon which the collars are based.

Oil Production

	2003				
		Weighted Average			
Area (Range of Sold Call Prices)	**Bbls/Day**	**Sold Put Price Per Bbl**	**Purchased Put Price Per Bbl**	**Sold Call Price Per Bbl**	**Months of Production**
United States ($27.25 - $29.00)	43,000	$19.00	$23.00	$27.98	Oct - Dec
International ($29.13 - $29.30)	10,000	$21.00	$25.00	$29.22	Oct - Dec

Gas Production

	2003				
		Weighted Average			
Area (Range of Sold Call Prices)	**MMBtu/ Day**	**Sold Put Price Per MMBtu**	**Purchased Put Price Per MMBtu**	**Sold Call Price Per MMBtu**	**Months of Production**
United States ($4.51 - $4.52)	50,000	$2.50	$3.50	$4.52	Oct - Dec
United States ($5.18 - $5.53)	70,000	$2.50	$3.50	$5.34	Oct - Dec

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of oil and gas may have on the fair value of its commodity hedging instruments. At October 15, 2003, a 10% increase in the underlying commodities' prices would have reduced the fair value of Devon's commodity hedging instruments by $180 million.

Interest Rate Risk

At September 30, 2003, Devon had debt outstanding of $8.9 billion. Of this amount, $8.3 billion, or 92%, bears interest at fixed rates averaging 6.7%. The remaining $0.6 billion of debt outstanding bears interest at floating rates which averaged 2.1% as of September 30, 2003.

The terms of Devon's various floating rate debt facilities (revolving credit facilities and term loan credit facility) allow interest rates to be fixed at Devon's option for periods of between seven to 180 days. A 10% increase in short-term interest rates on the floating-rate debt outstanding as of September 30, 2003 would equal approximately 21 basis points. Such an increase in interest rates would increase Devon's 2003 interest expense by less than $1 million assuming borrowed amounts remain outstanding for the remainder of 2003.

Devon has also entered into a floating-to-fixed interest rate swap and fixed-to-floating interest rate swaps to manage its exposure to interest rate volatility. Under the floating-to-fixed interest rate swap, Devon will record a fixed rate of 6.4% on $92 million of debt in 2003 through 2006 and 6.3% on $29 million of debt in 2007. Assuming index interest rates remain constant, under the fixed-to-floating interest rate swaps, Devon will record a floating rate of 2.9% on $0.3 billion of debt in 2003, 2.8% on $1.3 billion of debt in 2004, 2.6% on $1.2 billion of debt in 2005, 1.2% on $0.7 billion of debt in 2006 and 1.5% on $0.4 billion of debt in 2007. The amount of gains or losses realized from such swaps are included as increases or decreases to interest expense.

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in interest rates may have on the fair value of its interest rate swap instruments. At September 30, 2003, a 10% increase in the underlying interest rates would have decreased the fair value of Devon's interest rate swaps by $5 million.

The above sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments.

Foreign Currency Risk

Devon's Canadian subsidiary has $400 million of fixed-rate senior notes which are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar between the beginning and end of a reporting period increase or decrease the Canadian dollar equivalent balance of this debt. Such changes in the Canadian dollar equivalent balance of the debt are required to be included in determining net earnings for the period in which the exchange rate changes. Because of the variability of the exchange rate, it is not possible to estimate the effect which will be recorded in 2003. However, based on the September 30, 2003, Canadian-to-U.S. dollar exchange rate of $0.7405, for every $0.01 change in the exchange rate, Devon will record an effect (either income or expense) of approximately $7 million Canadian dollars during the last three months of 2003. The resulting revenue or expense in U.S. dollars will depend on the currency exchange rate in effect during the last three months of the year. The $400 million becomes due in March 2011. Until then, the gains or losses caused by the exchange rate fluctuations have no effect on cash flow.

Devon also has Canadian and U.S. dollar foreign currency exchange rate swaps. A portion of Devon's Canadian gas sales is based on U.S. dollar prices. Therefore, currency fluctuations between the Canadian and U.S. dollars impact the amount of Canadian dollars received by Devon's Canadian subsidiaries for this gas production. These foreign currency exchange rate swaps mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on Canadian gas revenues. Under these swap agreements, for the last three months of 2003, Devon will sell $3 million at average Canadian-to-U.S. exchange rates of $0.676, and buy the same amount of dollars at the floating exchange rate. The amount of gains or losses realized from such swaps are included as increases or decreases to realized gas sales. At the September 30, 2003 exchange rate, these swaps would result in an increase to gas sales during the last three months of less than $1 million. A 10% decrease in the Canadian-to-U.S. dollar exchange rate would result in a decrease to gas sales during the last three months of 2003 of less than $1 million.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our principal executive and financial officers have evaluated our disclosure controls and procedures and have determined that such disclosure controls and procedures were effective as of the end of the period covered by this Quarterly Report on Form 10-Q.

Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. ***Legal Proceedings***

None

Item 2. ***Changes in Securities***

None

Item 3. ***Defaults Upon Senior Securities***

None

Item 4. ***Submission of Matters to a Vote of Security Holders***

None

Item 5. ***Other Information***

None

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Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits required by Item 601 of Regulation S-K are as follows:

Exhibit Number	
31.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of William T. Vaughn, Chief Financial Officer of Registrant, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of William T. Vaughn, Chief Financial Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(b) Reports on Form 8-K

A Report on Form 8-K was furnished pursuant to Item 12 on August 7, 2003 to announce Devon’s second quarter results.

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SIGNATURES

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

DEVON ENERGY CORPORATION

Date: November 12, 2003

/s/ Danny J. Heatly

Danny J. Heatly
Vice President — Accounting

INDEX TO EXHIBITS

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Exhibit 31.1

**CERTIFICATION PURSUANT TO
RULE 13a-14(a)/15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, J. Larry Nichols, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Devon Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 12, 2003

/s/ J. Larry Nichols

J. Larry Nichols
Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
RULE 13a-14(a)/15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, William T. Vaughn, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Devon Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 12, 2003

/s/ William T. Vaughn

William T. Vaughn
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Report of Devon Energy Corporation (“Devon”) on Form 10-Q for the period ended September 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, J. Larry Nichols, Chief Executive Officer of Devon, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

/s/ J. Larry Nichols

J. Larry Nichols
Chief Executive Officer
November 12, 2003

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Report of Devon Energy Corporation ("Devon") on Form 10-Q for the period ended September 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William T. Vaughn, Chief Financial Officer of Devon, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

/s/ William T. Vaughn

William T. Vaughn
Chief Financial Officer
November 12, 2003