DEVON ENERGY CORP/DE

FORM 10-Q
(Quarterly Report)

Filed 11/14/01 for the Period Ending 09/30/01

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 11/14/2001 For Period Ending 9/30/2001

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)

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

For the Quarterly Period Ended September 30, 2001

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 (State or Other Jurisdiction of Incorporation or Organization)	73-1567067 (I.R.S. Employer Identification Number)
20 N. Broadway, Suite 1500 Oklahoma City, Oklahoma (Address of Principal Executive Offices)	73102 (Zip Code)

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

Not applicable

Former name, former address and former fiscal year, if changed from last report.

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 |X| No |_|.

The number of shares outstanding of Registrant's common stock, par value $.10, as of November 1, 2001, was 126,014,000.

1 of 68 total pages

(Exhibit Index is found at page 64)

DEVON ENERGY CORPORATION

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to the Securities and Exchange Commission

Page No.

DEFINITIONS

As used in this document:

"Mcf" means thousand cubic feet
"MMcf" means million cubic feet
"Bcf" means billion cubic feet
"Bbl" means barrel
"MBbls" means thousand barrels
"MMBbls" means million barrels
"Boe" means equivalent barrels of oil

"MBoe" means thousand equivalent barrels of oil "Oil" includes crude oil and condensate "NGL" means natural gas liquids

DEVON ENERGY CORPORATION

Part I. Financial Information

Item 1. Consolidated Financial Statements
September 30, 2001 and 2000

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
(In Thousands, Except Share Data)

	September 30, 2001 (Unaudited)	December 31, 2000
Assets		
Current assets:		
Cash and cash equivalents	$ 239,265	228,050
Accounts receivable	491,099	615,463
Inventories	42,618	47,272
Deferred income taxes	8,979	8,979
Investments and other current assets	37,941	34,373
Total current assets	819,902	934,137
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($453,667 and $315,260 excluded from amortization in 2001 and 2000, respectively)	11,131,091	9,709,352
Less accumulated depreciation, depletion and amortization	5,387,568	4,799,816
	5,743,523	4,909,536
Investment in ChevronTexaco Corporation common stock, at fair value	601,083	598,867
Goodwill, net of amortization	269,305	289,489
Fair value of derivative instruments	151,415	--
Other assets	147,262	128,449
Total assets	$ 7,732,490	6,860,478
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable:		
Trade	337,577	305,210
Revenues and royalties due to others	115,131	151,951
Income taxes payable	17,402	65,674
Accrued interest payable	32,269	23,191
Merger related expenses payable	11,602	36,981
Accrued expenses and other current liabilities	47,817	45,980
Total current liabilities	561,798	628,987
Other liabilities	162,318	164,469
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	645,461	760,313
Other long-term debt	1,339,316	1,288,523
Deferred revenue	65,330	113,756
Deferred income taxes	1,112,822	626,826
Fair value of derivative instruments	76,440	--
Stockholders' equity:		
Preferred stock of $1.00 par value ($100 liquidation value) Authorized 4,500,000 shares; issued 1,500,000 in 2001 and 2000	1,500	1,500
Common stock of $.10 par value Authorized 400,000,000 shares; issued 129,768,000 in 2001 and 128,638,000 in 2000	12,977	12,864
Additional paid-in capital	3,594,814	3,563,994
Retained earnings (accumulated deficit)	380,049	(214,708)
Accumulated other comprehensive loss	(29,542)	(85,397)
Unamortized restricted stock awards	(406)	(649)
Treasury stock, at cost; 3,754,000 shares in 2001	(190,387)	--
Total stockholders' equity	3,769,005	3,277,604
Total liabilities and stockholders' equity	$ 7,732,490	6,860,478

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
(In Thousands, Except Per Share Amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	2000	2001	2000
		(Unaudited)		
Revenues				
Oil sales	$ 234,116	267,430	722,672	812,365
Gas sales	306,808	392,588	1,474,986	960,865
Natural gas liquids sales	30,445	35,457	94,746	106,373
Other	15,346	29,666	43,060	54,438
Total revenues	586,715	725,141	2,335,464	1,934,041
Costs and expenses				
Lease operating expenses	124,781	108,902	362,884	326,709
Transportation costs	16,113	13,907	51,936	38,652
Production taxes	20,967	27,773	95,025	69,644
Depreciation, depletion and amortization of property and equipment	205,345	170,151	572,939	507,654
Amortization of goodwill	8,461	10,364	25,384	31,057
General and administrative expenses	26,977	25,304	73,867	74,177
Expenses related to prior merger	--	57,233	--	57,233
Interest expense	35,885	40,445	104,825	121,396
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	--	--	--	2,408
Change in fair value of derivative instruments	(2,738)	--	3,844	--
Reduction of carrying value of oil and gas properties	10,911	--	87,853	--
Total costs and expenses	446,702	454,079	1,378,557	1,228,930
Earnings before income tax expense and cumulative effect of change in accounting principle	140,013	271,062	956,907	705,111
Income tax expense (benefit)				
Current	(25,679)	50,403	117,213	122,908
Deferred	80,960	55,747	267,757	158,770
Total income tax expense	55,281	106,150	384,970	281,678
Earnings before cumulative effect of change in accounting principle	84,732	164,912	571,937	423,433
Cumulative effect of change in accounting principle, net of income tax expense of $31,617	--	--	49,452	--
Net earnings	84,732	164,912	621,389	423,433
Preferred stock dividends	2,433	2,433	7,301	7,301
Net earnings applicable to common stockholders	$ 82,299	162,479	614,088	416,132
Net earnings before cumulative effect of change in accounting principle per average common share outstanding:				
Basic	$ 0.65	1.27	4.40	3.27
Diluted	$ 0.64	1.22	4.26	3.20
Net earnings per average common share outstanding:				
Basic	$ 0.65	1.27	4.79	3.27
Diluted	$ 0.64	1.22	4.63	3.20
Weighted average common shares outstanding-basic	126,335	127,857	128,274	127,065
Weighted average common shares outstanding-diluted	131,573	134,394	133,982	130,628

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Comprehensive Earnings
(In Thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	2000	2001	2000
			(Unaudited)	
Net earnings	$ 84,732	164,912	621,389	423,433
Other comprehensive earnings (loss):				
Foreign currency translation adjustments	(17,068)	(6,462)	(20,820)	(12,237)
Cumulative effect of change in accounting principle	--	--	(36,579)	--
Reclassification adjustment for derivative (gains) losses reclassified into oil and gas sales	(8,285)	--	6,678	--
Change in fair value of outstanding hedging positions	64,001	--	105,224	--
Unrealized losses on marketable securities, net of tax benefit	(24,877)	(1,288)	1,352	(7,330)
Comprehensive earnings	$ 98,503	157,162	677,244	403,866

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(In Thousands)

	Nine Months Ended September 30, 2001	2000
	(Unaudited)	
Cash flows from operating activities		
Net earnings	$ 621,389	423,433
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation, depletion and amortization of property and equipment	572,939	507,654
Amortization of goodwill	25,384	31,057
Reduction of carrying value of oil and gas properties	87,853	--
Accretion of interest on long-term debt	11,598	3,531
Amortization of discounts (premiums) on other long-term debt	6,130	(2,891)
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	--	2,408
Loss (gain) on sale of assets	247	(5,854)
Change in fair value of derivative instruments	3,844	--
Cumulative effect of change in accounting principle	(49,452)	--
Deferred income taxes	267,757	158,770
Other	965	(28)
Changes in assets and liabilities:		
Decrease (increase) in:		
Accounts receivable	113,769	(153,432)
Inventories	5,723	(16,025)
Prepaid expenses	14,298	(22,751)
Other assets	(28,923)	(3,029)
(Decrease) increase in:		
Accounts payable	17,463	95,842
Income taxes payable	(48,176)	78,095
Accrued expenses and other current liabilities	(51,711)	37,198
Deferred revenue	(48,394)	23,545
Long-term other liabilities	(22,195)	(24,133)
Net cash provided by operating activities	1,500,508	1,133,390
Cash flows from investing activities		
Proceeds from sale of property and equipment	41,395	56,640
Capital expenditures	(1,351,492)	(947,974)
Net cash used in investing activities	(1,310,097)	(891,334)
Cash flows from financing activities		
Proceeds from borrowings of other long-term debt	1,271,746	2,258,549
Principal payments on revolving lines of credit	(1,263,995)	(2,473,568)
Issuance of common stock, net of issuance costs	30,932	37,500
Treasury stock purchased	(190,387)	(10,699)
Treasury stock issued	--	24,937
Dividends paid on common stock	(19,331)	(15,080)
Dividends paid on preferred stock	(7,301)	(7,301)
Decrease in long-term other liabilities	--	(49,802)
Net cash used in financing activities	(178,336)	(235,464)
Effect of exchange rate changes on cash	(860)	(1,112)
Net increase in cash and cash equivalents	11,215	5,480
Cash and cash equivalents at beginning of period	228,050	173,167
Cash and cash equivalents at end of period	$ 239,265	178,647

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

On August 29, 2000, Devon Energy Corporation ("Devon") and Santa Fe Snyder Corporation ("Santa Fe Snyder") completed a merger of the two companies (the "Santa Fe Snyder merger"). At that date, Santa Fe Snyder became a wholly-owned subsidiary of Devon. The Santa Fe Snyder merger was accounted for under the pooling-of-interests method of accounting for business combinations. All operational and financial information contained herein includes the combined amounts of Devon and Santa Fe Snyder for all periods presented.

The accompanying consolidated financial statements and notes thereto 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 2000 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, 2001, and the results of their operations and their cash flows for the three-month and nine-month periods ended September 30, 2001 and 2000. Certain of the 2000 amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2001 presentation.

2. Pending Acquisitions

Mitchell Energy & Development Corp.

On August 14, 2001, Devon and Mitchell Energy & Development Corp. ("Mitchell Energy") announced that Devon will acquire Mitchell Energy for cash and stock. In the transaction, Mitchell Energy stockholders would receive, for each Mitchell common share, $31 cash and 0.585 of a share of Devon common stock. The purchase price will approximate $3.2 billion. The cash portion of the purchase price will be funded from a new $3.0 billion senior unsecured term loan credit facility (see Note 3). The transaction is subject to approval by the stockholders of both companies, as well as certain regulatory approvals. If approved, the transaction is expected to be consummated shortly after the stockholder meetings.

Mitchell Energy's estimated September 30, 2001 proved oil and gas reserves totaled 408 million barrels of oil equivalent located in the United States. In the transaction, Devon would also acquire Mitchell Energy's natural gas processing plants, pipelines and other midstream assets valued at approximately $840 million.

2. Pending Acquisitions (Continued)

Anderson Exploration Ltd.

On October 12, 2001, Devon accepted all of the Anderson Exploration Ltd. ("Anderson") common shares tendered by Anderson stockholders in the tender offer, which represented approximately 97% of the outstanding Anderson common shares. On October 17, 2001, Devon completed its acquisition of Anderson by a compulsory acquisition under the Canada Business Corporations Act of the remaining 3% of Anderson common shares. The cost to Devon of acquiring Anderson's outstanding common shares and paying for the intrinsic value of Anderson's outstanding options and appreciation rights was approximately $3.5 billion, which was funded from the sale of $3.0 billion of debt securities and borrowings under the $3.0 billion senior unsecured term loan credit facility (see Note 3).

Proved reserves acquired by Devon in the Anderson transaction totaled approximately 522 million barrels of oil equivalent, all of which are located in Canada.

3. Long-Term Debt

Debt Securities

On October 3, 2001, Devon, through its wholly-owned financing subsidiary Devon Financing Corporation, U.L.C. ("Devon Financing"), sold $1.75 billion of 6.875% notes due September 30, 2011 and $1.25 billion of 7.875% debentures due September 30, 2031. The debt securities are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the Anderson acquisition.

The $3.0 billion of debt securities were structured in a manner that results in an expected weighted average after-tax borrowing rate of approximately 1.76%.

Interest on the debt securities will be payable by Devon Financing semiannually on March 30 and September 30 of each year, beginning on March 30, 2002. The indenture governing the debt securities limits both Devon Financing's and Devon's ability to incur liens or enter into mergers or consolidations, or transfer all or substantially all of their respective assets, unless the successor company assumes Devon Financing's or Devon's obligations under the indenture.

New Term Loan Credit Facility

On October 12, 2001, Devon and Devon Financing entered into a new $3.0 billion senior unsecured term loan credit facility arranged by UBS Warburg LLC and Banc of America Securities LLC. The facility has a term of five years. Devon and Devon Financing may borrow funds under this facility subject to conditions usual in commercial transactions of this nature, including the absence of any default under this facility. Interest on borrowings under this facility may be based, at the borrower's option, on the London Interbank Offered Rate ("LIBOR") or on UBS Warburg's base rate (which is the higher of UBS Warburg's prime commercial lending rate and the weighted average of rates on overnight Federal funds transactions with members of the Federal Reserve System plus 0.50%).

The interest rates will include a margin determined by Devon's long-term senior unsecured debt rating. Notwithstanding the current debt rating, the margin for borrowings based on LIBOR will be an additional 1.0% for the six-month period following completion of the syndication of this facility to a broader group of lenders, which is expected to occur in November 2001. Based on LIBOR rates as of October 30, 2001, Devon's rate would be 3.17%. In addition, the lenders under this facility will be charging Devon a per annum availability fee on their daily average unused lending commitments equal to a percentage determined by Devon's long-term senior unsecured debt rating.

On October 15, 2001, Devon used proceeds of $0.8 billion from borrowings on this facility, along with the $3.0 billion of proceeds from the debt securities referred to previously, to complete the Anderson acquisition, and to pay down Anderson's outstanding bank debt and other related fees and expenses. Devon expects substantially all of the remaining $2.2 billion of availability to be utilized upon the closing of the Mitchell acquisition. No borrowings under this facility may be made after September 13, 2002.

On a pro forma basis, assuming that $3.0 billion were drawn against this facility, the terms of this facility would require repayment of the debt during the following years:

	(billions)
2001	$ --
2002	$ --
2003	$ --
2004	$0.2
2005	$1.2
2006	$1.6

The terms of this facility also provide that voluntary prepayments of the debt are applied to the earliest scheduled maturities first. For example, if Devon were to prepay a portion of the $3.0 billion of debt with proceeds from property sales, the amount of the prepayment would reduce the amounts otherwise due first in 2004, then 2005 and finally 2006.

This credit facility contains certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio as defined in the credit facility.

Amendment of Existing Credit Facilities

On August 13, 2001, Devon renewed its 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").

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 $0.9 million that is payable quarterly.

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 August 12, 2002 (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. Debt borrowed under the Tranche B facility matures two years and one day following the end of the Tranche B Revolving Period. On September 30, 2001, there were no borrowings outstanding under the $725 million U.S. Facility.

Devon may borrow funds under the $275 million Canadian Facility until August 12, 2002 (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 45 and 90 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 semi annual 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, 2001, there was $60.2 million borrowed under the $275 million Canadian facility at an average interest rate of 3.9%.

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.

3. Long-Term Debt (continued)

The agreements governing the Credit Facilities contain certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio as defined in the agreements.

Commercial Paper

As of September 30, 2001, Devon had $129.8 million of borrowings under its commercial paper program at an average rate of 3.2%. Because Devon had the intent and ability to refinance the balance due with borrowings under its Credit Facilities, the $129.8 million outstanding under the commercial paper program was classified as long-term debt on the September 30, 2001 consolidated balance sheet.

4. Derivative Instruments and Hedging Activities

As of January 1, 2001, Devon adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Certain Hedging Activities" and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS No. 133." SFAS No. 133 and SFAS No. 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. In accordance with the transition provisions of SFAS No. 133, Devon recorded a net-of-tax cumulative-effect-type adjustment of $36.6 million loss in accumulated other comprehensive loss to recognize at fair value all derivatives that are designated as cash-flow hedging instruments. Additionally, Devon recorded a net-of-tax cumulative-effect-type adjustment to net earnings of $49.5 million gain ($0.38 per basic share and $0.37 per diluted share) related to the fair value of derivative instruments that do not qualify as hedges. This gain related principally to the option embedded in Devon's debentures that are exchangeable into shares of ChevronTexaco Corporation common stock.

All derivatives are recognized on the balance sheet at their fair value. All of Devon's derivatives that qualify for hedge accounting treatment are either "cash flow" hedges or "foreign currency cash flow" hedges (collectively, "cash flow hedges"). Devon designates its cash flow hedge derivatives as such on the date the derivative contract is entered into. Devon formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. Devon also assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

During the first nine months of 2001, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of Devon's derivatives.

By using derivative instruments to hedge exposures to changes in commodity prices and exchange rates, Devon exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are usually placed with counterparties that Devon believes are minimal credit risks.

4. Derivative Instruments and Hedging Activities (Continued)

Market risk is the adverse effect on the value of a derivative instrument that results from a change in interest rates, commodity prices, or currency exchange rates. The market risk associated with commodity price and foreign exchange contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

Devon periodically enters into financial hedging activities with respect to a portion of its projected oil and natural gas production through various financial transactions to manage its exposure to oil and gas price volatility. 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. These transactions also include 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. The oil and gas reference prices upon which these price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon.

Devon also periodically enters into 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 Canadian oil revenues that are predominantly based on U.S. dollar prices.

Devon does not hold or issue derivative instruments for trading purposes. All of Devon's commodity price swaps and costless price collars and foreign exchange rate swaps in place at January 1, 2001 and September 30, 2001 have been designated as cash flow hedges. Changes in the fair value of these derivatives are reported on the balance sheet in "Accumulated other comprehensive loss" ("AOCL"). These amounts are reclassified to oil and gas sales when the forecasted transaction takes place.

During the third quarter of 2001, Devon entered into foreign exchange forward contracts to mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on the Anderson acquisition. Under SFAS 133, these derivative instruments were not considered hedges and, as such, the change in fair value of these contracts is included in the statements of operations as part of the change in fair value of derivative instruments.

During the third quarter of 2001, Devon also entered into interest rate locks to reduce exposure to the variability in market interest rates, specifically U.S. Treasury rates, in anticipation of the sale of the debt securities discussed in Note 3. These derivative instruments were designated as cash flow hedges and, as such, the change in fair value of these contracts is included on the balance sheet in AOCL.

4. Derivative Instruments and Hedging Activities (Continued)

Devon assesses the effectiveness of its hedges based on changes in the derivative's intrinsic value. The change in the time value of the derivative is excluded from the assessment of hedge effectiveness and, along with any ineffectiveness, is recorded on the statement of operations in "Change in fair value of derivative instruments." For the three- and nine-month periods ended September 30, 2001, Devon recorded a net charge of approximately $1.4 million which represented the ineffectiveness of the various cash flow hedges.

As of September 30, 2001, $79.7 million of net deferred gains on derivative instruments accumulated in AOCL are expected to be reclassified to earnings during the next 12 months. Transactions and events expected to occur over the next 12 months that will necessitate reclassifying these derivatives' gains to earnings are the production and sale of oil and gas which includes the production hedged under the various derivative instruments. The maximum term over which Devon is hedging exposures to the variability of cash flows for commodity price risk is 15 months.

Devon recorded in its statements of operations a gain of $4.1 million and a loss of $2.4 million in the three-month and nine-month periods ended September 30, 2001, respectively, for the change in fair value of derivative instruments that do not qualify for hedge accounting treatment.

5. Earnings Per Share

The following tables reconcile the net earnings and common shares outstanding used in the calculations of basic and diluted earnings per share for the three-month and nine-month periods ended September 30, 2001 and 2000.

	Net Earnings Applicable To Common Stockholders	Common Shares Outstanding	Net Earnings Per Share
		(In Thousands)	
Three Months Ended September 30, 2001:			
Basic earnings per share	$82,299	126,335	$0.65
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 $1,408,000)	2,201	4,377	
Potential common shares issuable upon the exercise of outstanding stock options	--	861	
Diluted earnings per share	$84,500	131,573	$0.64

5. Earnings Per Share (Continued)

	Net Earnings Applicable To Common Stockholders	Common Shares Outstanding	Net Earnings Per Share
Three Months Ended September 30, 2000:			
Basic earnings per share	$162,479	127,857	$1.27
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 $1,355,000)	2,119	4,377	
Potential common shares issuable upon the exercise of outstanding stock options	--	2,160	
Diluted earnings per share	$164,598	134,394	$1.22
Nine Months Ended September 30, 2001:			
Basic earnings per share	$614,088	128,274	$4.79
Dilutive effect of:			
Potential common shares issuable upon the conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $4,170,000)	6,522	4,377	
Potential common shares issuable upon the exercise of outstanding stock options	--	1,331	
Diluted earnings per share	$620,610	133,982	$4.63
Nine Months Ended September 30, 2000:			
Basic earnings per share	$416,132	127,065	$3.27
Dilutive effect of:			
Potential common shares issuable upon the conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $1,399,000)	2,189	1,534	
Potential common shares issuable upon the exercise of outstanding stock options	--	2,029	
Diluted earnings per share	$418,321	130,628	$3.20

5. Earnings Per Share (Continued)

Options to purchase approximately 3.0 million shares of Devon's common stock with exercise prices ranging from $45.49 per share to $89.66 per share (with a weighted average price of $55.58 per share) were excluded from the diluted earnings per share calculation for the third quarter of 2001 because the options' exercise price exceeded the average market price of Devon's common stock during the third quarter. Similarly, options to purchase approximately 1.1 million shares of Devon's common stock with exercise prices ranging from $56.19 per share to $89.66 per share (with a weighted average price of $66.14 per share) were excluded from the diluted earnings per share calculation for the third quarter of 2000.

Options to purchase approximately 1.1 million shares of Devon's common stock, with exercise prices from $52.39 to $89.66 per share (with a weighted average price of $63.44 per share), were excluded from the diluted earnings per share calculation for the first nine months of 2001 because the options' exercise price exceeded the average market price of Devon's common stock during the period. Similarly, options to purchase approximately 1.2 million shares of Devon's common stock with exercise prices ranging from $52.89 per share to $89.66 per share (with a weighted average price of $66.09 per share) were excluded from the diluted earnings per share calculation for the first nine months of 2000. The excluded options for each of the 2001 periods expire between November 8, 2001 and June 30, 2011.

6. Stock Buyback

Effective June 27, 2001, the board of directors authorized the repurchase of up to $1 billion of Devon's common stock. The repurchase program also applies to securities that are convertible into, or otherwise equity-linked to, Devon's common stock. Under the repurchase program, share purchases may be made from time to time depending upon market conditions and may be made in the open market and in privately negotiated transactions. The repurchase program may be discontinued at any time. Devon currently has suspended the share repurchase program.

During the third quarter of 2001, Devon repurchased 3,601,000 shares of common stock at an aggregate cost of $182.6 million or $50.70 per share. As of September 30, 2001, Devon had repurchased 3,754,000 shares of common stock at an aggregate cost of $190.4 million or $50.71 per share.

In addition to the aforementioned share repurchase program begun in the second quarter of 2001, Devon also repurchased shares of its common stock in the first quarter of 2001 under an odd-lot repurchase program. Pursuant to this program, Devon purchased and retired 232,000 shares of its common stock for a total cost of $13.3 million, or $57.40 per share.

7. 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. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense, except as discussed in the following paragraph.

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

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

Based on oil and natural gas cash market prices as of September 30, 2001, Devon's domestic and Canadian costs to be recovered exceeded the related ceiling values by $497.5 million, and $45.1 million, respectively. These after-tax amounts would have resulted in pre-tax reductions of the carrying values of Devon's domestic and Canadian oil and gas properties of $815.5 million and $78.6 million, respectively, in the third quarter of 2001. However, the cash market prices of natural gas increased significantly during the month of October 2001. Based on cash market prices of oil and natural gas as of October 31, 2001, when the accompanying consolidated financial statements were published, Devon's domestic and Canadian ceilings as of September 30, 2001 exceeded the related costs to be recovered by $414.2 million and $173.9 million, respectively. Accordingly, Devon did not record a reduction of the carrying value of its domestic and Canadian oil and gas properties in the quarter ended September 30, 2001.

During the third quarter of 2001, Devon elected to discontinue operations in Thailand. During the second quarter of 2001, Devon elected to discontinue operations in Malaysia, Qatar and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, Devon determined that the properties did not meet Devon's internal criteria to justify further investment. Accordingly, during the third quarter and first nine months of 2001, Devon recorded a $10.9 million and $87.9 million charge associated with the impairment of these properties, respectively. The after-tax effect of these reductions was $6.7 million and $68.8 million, respectively.

8. Supplemental Cash Flow Information

Cash payments for interest in the first nine months of 2001 and 2000 were approximately $78.1 million and $150.5 million, respectively. Cash payments for federal, state and foreign income taxes in the first nine months of 2001 and 2000 were approximately $165.5 million and $52.3 million, respectively.

9. Segment Information

Devon manages its business by country. As such, Devon identifies its segments based on geographic areas. Devon has three 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 activities. Following is certain financial information regarding Devon's segments. The revenues reported are all from external customers.

	U.S.	Canada	International	Total
		(In Thousands)		
As of September 30, 2001:				
Current assets	$ 468,566	50,000	301,336	819,902
Property and equipment, net of accumulated depreciation, depletion and amortization	4,395,745	632,877	714,901	5,743,523
Investment in ChevronTexaco Corporation common stock	601,083	--	--	601,083
Goodwill, net of amortization	217,730	--	51,575	269,305
Fair value of derivative instruments	149,437	1,978	--	151,415
Other assets	135,172	75	12,015	147,262
Total assets	$5,967,733	684,930	1,079,827	7,732,490
Current liabilities	362,143	68,428	131,227	561,798
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	645,461	--	--	645,461
Other long-term debt	1,279,143	60,173	--	1,339,316
Deferred revenue	64,533	306	491	65,330
Deferred tax liabilities	950,695	126,691	35,436	1,112,822
Other liabilities	130,300	912	31,106	162,318
Fair value of derivative instruments	76,172	268	--	76,440
Stockholders' equity	2,459,286	428,152	881,567	3,769,005
Total liabilities and stockholders' equity	$5,967,733	684,930	1,079,827	7,732,490

	U.S.	Canada	International	Total
		(In Thousands)		
Three Months ended September 30, 2001:				
Revenues				
Oil sales	$ 147,753	28,333	58,030	234,116
Gas sales	269,367	33,558	3,883	306,808
Natural gas liquids sales	26,747	3,150	548	30,445
Other	10,197	476	4,673	15,346
Total revenues	454,064	65,517	67,134	586,715
Costs and expenses				
Lease operating expenses	89,509	17,056	18,216	124,781
Transportation costs	13,262	2,851	--	16,113
Production taxes	20,381	450	136	20,967
Depreciation, depletion and amortization of property and equipment	168,452	21,439	15,454	205,345
Amortization of goodwill	8,451	--	10	8,461
General and administrative expenses	24,780	1,630	567	26,977
Interest expense	34,602	1,028	255	35,885
Change in fair value of derivative instruments	(2,738)	--	--	(2,738)
Reduction of carrying value of oil and gas properties	--	--	10,911	10,911
Total costs and expenses	356,699	44,454	45,549	446,702
Earnings before income tax expense	97,365	21,063	21,585	140,013
Income tax expense (benefit)				
Current	(26,931)	507	745	(25,679)
Deferred	59,505	12,345	9,110	80,960
Total income tax expense	32,574	12,852	9,855	55,281
Net earnings	64,791	8,211	11,730	84,732
Preferred stock dividends	2,433	--	--	2,433
Net earnings applicable to common shareholders	$ 62,358	8,211	11,730	82,299
Capital expenditures	$ 277,148	44,279	11,306	332,733

9. Segment Information (Continued)

	U.S.	Canada	International	Total
		(In Thousands)		
Three months ended September 30, 2000:				
Revenues				
Oil sales	$173,130	31,860	62,440	267,430
Gas sales	351,237	38,202	3,149	392,588
Natural gas liquids sales	30,985	4,356	116	35,457
Other	28,304	1,181	181	29,666
Total revenues	583,656	75,599	65,886	725,141
Costs and expenses				
Lease operating expenses	80,889	13,315	14,698	108,902
Transportation costs	11,115	2,792	--	13,907
Production taxes	27,356	295	122	27,773
Depreciation, depletion and amortization of property and equipment	143,587	15,633	10,931	170,151
Amortization of goodwill	10,358	--	6	10,364
General and administrative expenses	23,063	2,263	(22)	25,304
Expenses related to merger	57,233	--	--	57,233
Interest expense	37,463	2,902	80	40,445
Total costs and expenses	391,064	37,200	25,815	454,079
Earnings before income tax expense	192,592	38,399	40,071	271,062
Income tax expense				
Current	46,168	595	3,640	50,403
Deferred	24,124	17,579	14,044	55,747
Total income tax expense	70,292	18,174	17,684	106,150
Net earnings	122,300	20,225	22,387	164,912
Preferred stock dividends	2,433	--	--	2,433
Net earnings applicable to common stockholders	$119,867	20,225	22,387	162,479
Capital expenditures	$173,542	29,449	25,956	228,947

9. Segment Information (Continued)

	U.S.	Canada	International	Total
	(In Thousands)			
Nine months ended September 30, 2001:				
Revenues				
Oil sales	$ 458,653	85,097	178,922	722,672
Gas sales	1,300,175	165,127	9,684	1,474,986
Natural gas liquids sales	81,382	12,471	893	94,746
Other	34,140	2,166	6,754	43,060
Total revenues	1,874,350	264,861	196,253	2,335,464
Costs and expenses				
Lease operating expenses	257,315	49,175	56,394	362,884
Transportation costs	43,312	8,624	--	51,936
Production taxes	93,207	1,343	475	95,025
Depreciation, depletion and amortization of property and equipment	465,030	60,724	47,185	572,939
Amortization of goodwill	25,352	--	32	25,384
General and administrative expenses	70,489	5,454	(2,076)	73,867
Interest expense	99,519	4,541	765	104,825
Change in fair value of derivative instruments	3,844	--	--	3,844
Reduction of carrying value of oil and gas properties	--	--	87,853	87,853
Total costs and expenses	1,058,068	129,861	190,628	1,378,557
Earnings before income tax expense and cumulative effect of change in accounting principle	816,282	135,000	5,625	956,907
Income tax expense				
Current	104,156	2,417	10,640	117,213
Deferred	200,252	57,950	9,555	267,757
Total income tax expense	304,408	60,367	20,195	384,970
Earnings (loss) before cumulative effect of change in accounting principle	511,874	74,633	(14,570)	571,937
Cumulative effect of change in accounting principle	49,452	--	--	49,452
Net earnings (loss)	561,326	74,633	(14,570)	621,389
Preferred stock dividends	7,301	--	--	7,301
Net earnings (loss) applicable to common shareholders	$ 554,025	74,633	(14,570)	614,088
Capital expenditures	$1,073,839	154,120	123,533	1,351,492

9. Segment Information (Continued)

	U.S.	Canada	International	Total
		(In Thousands)		
Nine months ended September 30, 2000:				
Revenues				
Oil sales	$ 550,806	89,028	172,531	812,365
Gas sales	846,070	106,046	8,749	960,865
Natural gas liquids sales	93,256	12,901	216	106,373
Other	50,220	3,503	715	54,438
Total revenues	1,540,352	211,478	182,211	1,934,041
Costs and expenses				
Lease operating expenses	238,109	38,540	50,060	326,709
Transportation costs	30,132	8,520	--	38,652
Production taxes	68,503	819	322	69,644
Depreciation, depletion and amortization of property and equipment	428,399	47,986	31,269	507,654
Amortization of goodwill	31,039	--	18	31,057
General and administrative expenses	65,815	7,058	1,304	74,177
Expenses related to merger	57,233	--	--	57,233
Interest expense	112,818	7,898	680	121,396
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	--	2,408	--	2,408
Total costs and expenses	1,032,048	113,229	83,653	1,228,930
Earnings before income tax expense	508,304	98,249	98,558	705,111
Income tax expense				
Current	110,494	1,574	10,840	122,908
Deferred	80,371	44,842	33,557	158,770
Total income tax expense	190,865	46,416	44,397	281,678
Net earnings	317,439	51,833	54,161	423,433
Preferred stock dividends	7,301	--	--	7,301
Net earnings applicable to common stockholders	$ 310,138	51,833	54,161	416,132
Capital expenditures	$ 720,013	107,606	120,355	947,974

10. 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.

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 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 the PennzEnergy merger 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, 2001, Devon's consolidated balance sheet included $7.7 million of accrued liabilities, reflected in "Other liabilities," for environmental remediation. 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) the availability of defenses to liability, including the availability of the "petroleum exclusion" under CERCLA and similar state laws, and/or (ii) Devon's current belief that its share of wastes at a particular site is or will be viewed by the Environmental Protection Agency or other PRPs as being de minimis. As a result, Devon's monetary exposure is not expected to be material.

Royalty Matters

More than 30 oil companies, including Devon, are involved in disputes in which it is alleged that such companies and related parties underpaid royalty, overriding royalty and working interests owners in connection with the production of crude oil. The proceedings include suits in federal court in Texas, Louisiana, Mississippi and Wyoming that have been consolidated into one proceeding in Texas. To avoid expensive and protracted litigation, certain parties, including Devon, have entered into a global settlement agreement which provides for a settlement of all claims of all members of the settlement class. The court held a fairness hearing and issued an Amended Final Judgment approving the settlement on September 10, 1999. However, certain entities appealed their objections to the settlement terms. The appeals were recently withdrawn and we expect to close the matter with payment expected to occur November 15, 2001. Devon's share of the settlement, which is accrued in the September 30, 2001 consolidated balance sheet, is not material to its financial position, results of operations or liquidity.

Also, pending in federal court in Texas is a similar suit alleging underpaid royalties to the United States in connection with natural gas and natural gas liquids produced and sold from United States owned and/or controlled lands. The claims were filed by private litigants against Devon and numerous other producers, under the federal False Claims Act. The United States served notice of its intent to intervene as to certain defendants, but not Devon. Devon and certain other defendants are challenging the constitutionality of whether a claim under the federal False Claims Act can be maintained absent government intervention. Devon believes that it has acted reasonably and paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this litigation. No liability has been recorded in connection with this dispute.

Maersk Rig Contract

In December 1997, the working interest owner partner of Pennzoil Venezuela Corporation, S.A. ("PVC"), a subsidiary of Devon as a result of the PennzEnergy merger, entered into a contract with Maersk Jupiter Drilling, S.A. ("Maersk") for the provision of a rig for drilling services relative to the anticipated drilling program associated with Devon's Block 70/80 in Lake Maracaibo, Venezuela. The rig was assembled and delivered by Maersk to Lake Maracaibo where it performed an abbreviated drilling program for both Blocks 68/79 and 70/80. It is currently stacked in Lake Maracaibo. The contract expires in the fourth quarter of 2001. As of September 30, 2001, Devon's consolidated balance sheet included accrued liabilities, reflected in "Other liabilities," for the expected cost to terminate/settle the contract. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the liability recognized for such termination/settlement of the contract.

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, 2001, compared to the three-month and nine-month periods ended September 30, 2000, and in financial condition since December 31, 2000. The discussion should be read in conjunction with Devon's 2000 annual report on Form 10-K.

Overview

Net earnings for the third quarter of 2001 were $84.7 million, or $0.65 per share. This compares to net earnings of $164.9 million, or $1.27 per share for the third quarter of 2000. Net earnings for the first nine months of 2001 were $621.4 million, or $4.79 per share. This compares to net earnings for the first nine months of 2000 of $423.4 million, or $3.27 per share. The decrease in third quarter earnings was due to decline in oil and natural gas prices partially offset by an increase in production. The increase in first nine months' earnings was due to higher natural gas prices and production.

On August 14, 2001, Devon and Mitchell Energy & Development Corp. ("Mitchell Energy") announced that Devon will acquire Mitchell Energy for cash and stock. In the transaction, Mitchell Energy stockholders will receive, for each Mitchell common share, $31 cash and 0.585 of a share of Devon common stock. The total purchase price will approximate $3.2 billion. The cash portion of the purchase price will be funded from a new $3.0 billion senior unsecured term loan credit facility. The transaction is subject to approval by the stockholders of both companies, as well as certain regulatory approvals. If approved, the transaction is expected to be consummated shortly after the stockholder meetings.

On October 3, 2001, Devon, through its wholly-owned financing subsidiary Devon Financing Corporation, U.L.C. ("Devon Financing"), sold $1.75 billion of 6.875% notes due September 30, 2011 and $1.25 billion of 7.875% debentures due September 30, 2031. The debt securities are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities.

On October 12, 2001, Devon accepted all of the Anderson Exploration Ltd. ("Anderson") common shares tendered by Anderson stockholders in the tender offer, which represented approximately 97% of the outstanding Anderson common shares. On October 17, 2001, Devon completed its acquisition of Anderson by a compulsory acquisition under the Canada Business Corporations Act of the remaining 3% of Anderson common shares. The cost to Devon of acquiring Anderson's outstanding common shares and paying for the intrinsic value of Anderson's outstanding options and appreciation rights was approximately $3.5 billion, which was funded from the sale of $3.0 billion of debt securities and borrowings under the $3.0 billion senior unsecured term loan credit facility.

On October 12, 2001, Devon and Devon Financing entered into a new $3.0 billion senior unsecured term loan credit facility arranged by UBS Warburg LLC and Banc of America Securities LLC. The facility has a term of five years. Devon and Devon Financing may borrow funds under this facility subject to conditions usual in commercial transactions of this nature, including the absence of any default under this facility. Interest on borrowings under this facility may be based, at the borrower's option, on the London Interbank Offered Rate ("LIBOR") or on UBS Warburg's base rate (which is the higher of UBS Warburg's prime commercial lending rate and the weighted average of rates on overnight Federal funds transactions with members of the Federal Reserve System plus 0.50%).

On October 15, 2001, Devon used proceeds of $0.8 billion from borrowings on this facility, along with the $3.0 billion of proceeds from the debt securities referred to previously, to complete the Anderson acquisition, and to pay down Anderson's outstanding bank debt and other related fees and expenses. Devon expects substantially all of the remaining $2.2 billion of availability to be utilized upon the closing of the Mitchell acquisition. No borrowings under this facility may be made after September 13, 2002.

Results of Operations

Total revenues decreased $138.4 million, or 19%, in the third quarter of 2001. This decline was the result of lower average oil, gas and NGL prices partially offset by increased oil, gas and NGL production. Oil, gas and NGL revenues were down $124.1 million, or 18%, for the third quarter of 2001 compared to the third quarter of 2000. Total revenues increased $401.4 million, or 21%, in the first nine months of 2001. This increase was the result of higher average gas prices and increased gas production. Oil, gas and NGL revenues were up $412.8 million, or 22%, for the first nine months of 2001 compared to the first nine months of 2000. 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,		
	2001	2000	Change	2001	2000	Change
Production						
Oil (MBbls)	10,410	10,147	+3%	30,844	32,241	-4%
Gas (MMcf)	113,570	106,114	+7%	333,853	316,084	+6%
NGL (MBbls)	1,934	1,688	+15%	4,881	5,384	-9%
Oil, Gas and NGLs (MBoe)(1)	31,272	29,521	+6%	91,367	90,306	+1%
Average Prices						
Oil (Per Bbl)	$ 22.49	26.36	-15%	23.43	25.20	-7%
Gas (Per Mcf)	2.70	3.70	-27%	4.42	3.04	+45%
NGL (Per Bbl)	15.74	21.01	-25%	19.41	19.76	-2%
Oil, Gas and NGLs (Per Boe)(1)	18.27	23.56	-22%	25.09	20.81	+21%
	(In Thousands)					
Revenues						
Oil	$234,116	267,430	-12%	722,672	812,365	-11%
Gas	306,808	392,588	-22%	1,474,986	960,865	+54%
NGL	30,445	35,457	-14%	94,746	106,373	-11%
Combined	$571,369	695,475	-18%	2,292,404	1,879,603	+22%

	Domestic					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2001	2000	Change	2001	2000	Change
Production						
Oil (MBbls)	6,622	6,638	0%	19,594	21,811	-10%
Gas (MMcf)	95,383	89,404	+7%	280,774	262,231	+7%
NGL (MBbls)	1,754	1,519	+15%	4,354	4,869	-11%
Oil, Gas and NGLs (MBoe)(1)	24,272	23,058	+5%	70,744	70,385	+1%
Average Prices						
Oil (Per Bbl)	$ 22.31	26.08	-14%	23.41	25.25	-7%
Gas (Per Mcf)	2.82	3.93	-28%	4.63	3.23	+44%
NGL (Per Bbl)	15.25	20.40	-25%	18.69	19.15	-2%
Oil, Gas and NGLs (Per Boe)(1)	18.29	24.09	-24%	26.01	21.17	+23%
	(In Thousands)					
Revenues						
Oil	$147,753	173,130	-15%	458,653	550,806	-17%
Gas	269,367	351,237	-23%	1,300,175	846,070	+54%
NGL	26,747	30,985	-14%	81,382	93,256	-13%
Combined	$443,867	555,352	-20%	1,840,210	1,490,132	+23%

	Canada					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2001	2000	Change	2001	2000	Change
Production						
Oil (MBbls)	1,291	1,234	+5%	3,912	3,598	+9%
Gas (MMcf)	15,507	14,477	+7%	46,212	47,263	-2%
NGL (MBbls)	145	162	-10%	473	504	-6%
Oil, Gas and NGLs (MBoe)(1)	4,022	3,809	+6%	12,087	11,979	+1%
Average Prices						
Oil (Per Bbl)	$ 21.95	25.82	-15%	21.75	24.74	-12%
Gas (Per Mcf)	2.16	2.64	-18%	3.57	2.24	+59%
NGL (Per Bbl)	21.72	26.89	-19%	26.37	25.60	+3%
Oil, Gas and NGLs (Per Boe)(1)	16.17	19.54	-17%	21.73	17.36	+25%
	(In Thousands)					
Revenues						
Oil	$ 28,333	31,860	-11%	85,097	89,028	-4%
Gas	33,558	38,202	-12%	165,127	106,046	+56%
NGL	3,150	4,356	-28%	12,471	12,901	-3%
Combined	$ 65,041	74,418	-13%	262,695	207,975	+26%

	International					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2001	2000	Change	2001	2000	Change
Production						
Oil (MBbls)	2,497	2,275	+10%	7,338	6,832	+7%
Gas (MMcf)	2,680	2,233	+20%	6,867	6,590	+4%
NGL (MBbls)	35	7	+400%	54	11	+391%
Oil, Gas and NGLs (MBoe)(1)	2,979	2,654	+12%	8,537	7,941	+8%
Average Prices						
Oil (Per Bbl)	$ 23.24	27.45	-15%	24.38	25.25	-3%
Gas (Per Mcf)	1.45	1.41	+3%	1.41	1.33	+6%
NGL (Per Bbl)	15.66	16.57	-6%	16.54	19.64	-16%
Oil, Gas and NGLs (Per Boe)(1)	20.97	24.76	-15%	22.20	22.86	-3%
	(In Thousands)					
Revenues						
Oil	$ 58,030	62,440	-7%	178,922	172,531	+4%
Gas	3,883	3,149	+23%	9,684	8,749	+11%
NGL	548	116	+372%	893	216	+313%
Combined	$ 62,461	65,705	-5%	189,499	181,496	+4%

1 Gas volumes are converted to Boe or MBoe 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. The respective prices of oil, gas and NGLs are affected by market and other factors in addition to relative energy content.

Oil Revenues. Oil revenues decreased $33.3 million, or 12%, in the third quarter of 2001. Oil revenues decreased $40.2 million due to a $3.87 per barrel decrease in the average price of oil in 2001. An increase in 2001's production of 0.3 million barrels caused oil revenues to increase by $6.9 million. This increase was primarily the result of the acquisition of certain domestic properties in the second quarter of 2001.

Oil revenues decreased $89.7 million, or 11%, in the first nine months of 2001. Oil revenues decreased $54.5 million due to a $1.77 per barrel decrease in the average price of oil in 2001. A decrease in production of 1.4 million barrels, or 4%, caused oil revenues to decrease by $35.2 million. This reduction was primarily the result of certain domestic and international properties which were sold prior to the 2001 period but whose production was included in the 2000 period.

Gas Revenues. Gas revenues decreased $85.8 million, or 22%, in the third quarter of 2001. Production rose 7.5 Bcf in the 2001 period, which added $27.6 million of gas revenues. A $1.00 per Mcf decrease in the average gas price in the third quarter of 2001 resulted in a $113.4 million decrease in gas revenues.

The largest contributors to the 2001 production increase were production added as a result of domestic drilling and development in Devon's coalbed methane properties as well as its other properties and production added by the acquisition of certain domestic properties in the second quarter of 2001.

In addition to these domestic increases, Canadian gas production increased 1.0 Bcf, or 7% in the 2001 quarter. New drilling, development and acquisitions as well as lower royalty rates, partially offset by natural declines, were the primary reasons for the production increase. The decrease in gas prices from the 2000 quarter to the 2001 quarter resulted in a decrease in the Canadian government's royalty percentage from 29.3% in the 2000 quarter to 25.5% in the 2001 quarter. Gross Canadian gas production, before royalties, was 20.8 Bcf in the 2001 quarter compared to 20.5 Bcf in the 2000 quarter.

Gas revenues increased $514.1 million, or 54%, in the first nine months of 2001. Production rose 17.8 Bcf in the 2001 period, which added $54.0 million of gas revenues. A $1.38 per Mcf increase in the average gas price in the first nine months of 2001 contributed $460.1 million of the increase in gas revenues.

The largest contributor to the 2001 production increase was production added as a result of domestic drilling and development in Devon's coalbed methane properties as well as its other properties.

These domestic increases were partially offset by a decline in Canadian gas production of 1.1 Bcf, or 2% in the first nine months of 2001. Natural declines and increased royalty rates, partially offset by new drilling, development and acquisitions, were the primary reasons for the production decline. The increase in gas prices from the 2000 period to the 2001 period resulted in an increase in the Canadian government's royalty percentage from 24.6% in the 2000 period to 27.1% in the 2001 period. Gross Canadian gas production, before royalties, was 63.4 Bcf in the 2001 period compared to 62.7 Bcf in the 2000 period.

NGL Revenues. NGL revenues decreased $5.0 million, or 14%, in the third quarter of 2001. A decrease in the average price of $5.27 per barrel, or 25%, caused NGL revenues to decrease $10.2 million in the 2001 quarter. A production increase of 0.2 million barrels caused revenues to increase $5.2 million. This increase was primarily the result of increased production in the Gulf of Mexico.

NGL revenues decreased $11.6 million, or 11%, in the first nine months of 2001. A decrease in the average price of $0.35 per barrel, or 2%, caused NGL revenues to decrease $1.7 million in the first nine months of 2001. A production decrease of 0.5 million barrels caused revenues to decrease $9.9 million. The production drop was primarily the result of certain domestic properties which were sold prior to the 2001 period but whose production was included in the 2000 period and a temporary shutdown of a gas processing plant in the Gulf of Mexico during the first quarter of 2001.

Production and Operating Expenses. The components of production and operating expenses are set forth in the following tables.

	Total					
	Three Months Ended September 30,			Nine Months Ended September 30,		
	2001	2000	Change	2001	2000	Change
Absolute (Thousands)						
Recurring operations and maintenance expenses	$119,675	102,436	+17%	349,387	314,272	+11%
Well workover expenses	5,106	6,466	-21%	13,497	12,437	+9%
Transportation costs	16,113	13,907	+16%	51,936	38,652	+34%
Production taxes	20,967	27,773	-25%	95,025	69,644	+36%
Total production and operating expenses	$161,861	150,582	+7%	509,845	435,005	+17%
Per Boe						
Recurring operations and maintenance expenses	3.83	3.47	+10%	3.82	3.48	+10%
Well workover expenses	0.16	0.22	-25%	0.15	0.14	+7%
Transportation costs	0.52	0.47	+9%	0.57	0.43	+33%
Production taxes	0.67	0.94	-29%	1.04	0.77	+35%
Total production and operating expenses	$ 5.18	5.10	+2%	5.58	4.82	+16%

Recurring operations and maintenance expenses increased $17.2 million, or 17%, in the third quarter of 2001. Recurring operations and maintenance expenses increased $35.1 million, or 11%, in the first nine months of 2001. These increases were primarily the result of increases in many third-party field service costs, fuel and electricity costs as well as increases in production.

Transportation costs increased $2.2 million, or 16%, in the third quarter of 2001. Transportation costs increased $13.3 million, or 34%, in the first nine months of 2001. These increases were primarily due to an increase in coalbed methane gas production and increases in transportation rates.

Production taxes decreased $6.8 million, or 25%, in the 2001 quarter. Also, production taxes increased $25.4 million, or 36%, in the first nine months of 2001. 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 20% decrease and 23% increase in domestic oil, gas and NGL revenues in the third quarter and first nine months of 2001, respectively, was a primary cause of the production tax changes. Production taxes did not change proportionately to the change in revenues. This was primarily due to the fact that most of the change in domestic revenues occurred in the Rocky Mountain division which has higher production tax rates than the other domestic divisions.

Depreciation, Depletion and Amortization Expenses ("DD&A"). Oil and gas property related DD&A increased $33.0 million, or 20%, from $162.7 million in the third quarter of 2000 to $195.7 million in the third quarter of 2001. DD&A increased $9.6 million in the 2001 quarter due to the 6% increase in combined oil, gas and NGL production in the 2001 quarter. An increase in the combined DD&A rate from $5.51 per Boe in the 2000 quarter to $6.26 per Boe in the 2001 quarter caused oil and gas property related DD&A to increase $23.4 million. The $0.75 increase in the 2001 rate over the 2000 rate is primarily the result of an increase in future development costs and the acquisition of certain properties during 2001, partially offset by an increase in total reserves.

Oil and gas property related DD&A increased $57.5 million, or 12%, from $486.1 million in the first nine months of 2000 to $543.6 million in the first nine months of 2001. An increase in the combined DD&A rate from $5.38 per Boe in the year-to-date 2000 period to $5.95 per Boe in the year-to-date 2001 period caused oil and gas property related DD&A to increase $51.8 million. The $0.57 increase in the 2001 rate over the 2000 rate is primarily the result of an increase in future development costs, the acquisition of certain properties during 2001 and the disposition of certain properties during 2000, partially offset by an increase in total reserves. DD&A increased $5.7 million in the year-to-date 2001 period due to the 1% increase in combined oil, gas and NGL production in the first nine months of 2001.

Non-oil and gas property DD&A expense increased $2.1 million to $9.6 million in the third quarter of 2001 compared to $7.5 million in the third quarter of 2000. Non-oil and gas property DD&A expense increased $7.8 million to $29.3 million in the first nine months of 2001 compared to $21.5 million in the first nine months of 2000. Depreciation of new non-oil and gas property and the gas pipeline and gathering system in Wyoming accounted for the increase.

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 2001 and 2000.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	2000	2001	2000
	(In Thousands)			
Gross G&A	$ 60,025	52,888	172,132	158,054
Capitalized G&A	(18,115)	(17,416)	(56,906)	(45,918)
Reimbursed G&A	(14,933)	(10,168)	(41,359)	(37,959)
Net G&A	$ 26,977	25,304	73,867	74,177

Net G&A increased $1.7 million, or 7%, in the third quarter of 2001 and decreased $0.3 millionin the first nine months of 2001 compared to the same periods of 2000, respectively. Gross G&A increased $7.1 million and $14.1 million, or 13% and 9%, in the third quarter and first nine months of 2001 compared to the same periods of 2000, respectively. The increases in gross expenses in the third quarter and first nine months of 2001 were primarily related to additional personnel related costs and expenses related to possible acquisitions which were not completed.

Net G&A was reduced $0.7 million and $11.0 million in the third quarter and first nine months of 2001, respectively, due to an increase in the amount capitalized as part of oil and gas properties. The increase in capitalized G&A was primarily related to additional personnel related costs and increased acquisition, exploration and development activities. G&A was also reduced $4.8 million and $3.4 million in the third quarter and first nine months of 2001, respectively, due to an increase in the amount of reimbursements on operated properties in the 2001 periods.

Interest Expense. Interest expense decreased $4.6 million and $16.6 million, or 11% and 14%, in the third quarter and first nine months of 2001 as compared to the corresponding periods of 2000, respectively, due to a decrease in the average debt balance outstanding as well as a decrease in the annualized interest rates for both periods. The decrease in the average debt balance in both the third quarter and first nine months of 2001 was primarily attributable to the repayment of long-term debt from excess cash flow. The annualized interest rate dropped from 6.7% in the third quarter of 2000 to 6.5% in the third quarter of 2001. The annualized interest rate dropped from 6.8% in the first nine months of 2000 to 6.7% in the first nine months of 2001.

Pursuant to the adoption of Financial Accounting Standards Board Statement of Financial Accounting Standards No. 133 ("SFAS No. 133") effective January 1, 2001, the debentures that are exchangeable into shares of ChevronTexaco Corporation common stock were revalued as of August 17, 1999. This is the date the debentures were assumed as part of the PennzEnergy merger. Under SFAS No. 133, the total fair value of the debentures was allocated between the interest-bearing debt and the option that is embedded in the debentures. Accordingly, the debt portion of the debentures was reduced by $139.6 million as of August 17, 1999. This discount is being accreted in interest expense, which has raised the effective interest rate on the debentures to 7.76% in the third quarter and first nine months of 2001 compared to 4.92% recorded prior to 2001. The accretion in the third quarter and first nine months of 2001 was $3.1 million and $9.2 million, respectively.

The following schedule includes the components of interest expense for the third quarter and first nine months of 2001 and 2000.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	2000	2001	2000
	(In Thousands)			
Interest based on debt outstanding	$ 33,301	41,217	97,709	123,261
Amortization of debt premiums (discounts)	2,103	(945)	6,130	(2,891)
Facility and agency fees	293	539	837	2,361
Amortization of capitalized loan costs	300	367	901	1,261
Capitalized interest	(702)	(931)	(2,016)	(2,473)
Other	590	198	1,264	(123)
Total interest expense	$ 35,885	40,445	104,825	121,396

Reduction of carrying value of oil and gas properties. During the third quarter of 2001, Devon elected to discontinue operations in Thailand. After meeting the drilling and capital commitments on this property, Devon determined that the property did not meet Devon's internal criteria to justify further investment. Accordingly, during the third quarter of 2001, Devon recorded a $10.9 million charge associated with the impairment of this property. The after-tax effect of this reduction was $6.7 million.

During the first nine months of 2001, Devon elected to discontinue operations in Thailand, Malaysia, Qatar and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, Devon determined that these properties did not meet Devon's internal criteria to justify further investment. Accordingly, during the first nine months of 2001, Devon recorded an $87.9 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $68.8 million.

Due to volatility in oil and gas prices and the effect of the Anderson and Mitchell acquisitions, there is a possibility that Devon would have to record a reduction in the carrying value of its oil and gas properties as of December 31, 2001.

Change in Fair Value of Derivative Instruments. As a result of the adoption of SFAS No. 133 effective January 1, 2001, all derivatives are included on the balance sheet at their fair value. The $2.7 million gain and $3.8 million loss included in the third quarter and first nine months of 2001, respectively, represent the change in the fair value of derivatives that do not qualify as hedges and the ineffectiveness from designated cash flow hedges.

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 2001 was 40% compared to 39% in the third quarter of 2000. The estimated effective tax rate was 40% in both the first nine months of 2001 and the first nine months of 2000.

Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("Statement 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," Statement 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, 2001, were approximately $208 million of net operating loss carryforwards. The 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 2002 and 2014, Canadian carryforwards which expire primarily between 2001 and 2007 and minimum tax credits which have no expiration. Devon expects the tax benefits from the net operating loss carryforwards to be utilized between 2001 and 2006. 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.

Cumulative Effect of Change in Accounting Principle. At the time of adoption of SFAS No. 133, Devon recorded a cumulative-effect-type adjustment to net earnings for a $49.5 million gain related to the fair value of derivatives that do not qualify as hedges. This gain included $46.2 million related to the option embedded in the debentures that are exchangeable into shares of ChevronTexaco Corporation common stock.

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 included elsewhere herein.

Capital Expenditures. Approximately $1.4 billion was spent in the first nine months of 2001 for capital expenditures. This total includes $0.5 billion for the acquisition of oil and gas properties and $0.9 billion for the drilling or development of oil and gas properties. Approximately $0.9 billion was spent for capital expenditures in the first nine months of 2000. This total includes $0.2 billion for the acquisition of oil and gas properties and $0.7 billion for the drilling or development of oil and gas properties.

Capital Resources and Liquidity. Net cash provided by operating activities ("operating cash flow") continued to be the primary source of capital and liquidity in the first nine months of 2001. Operating cash flow in the first nine months of 2001 was $1.5 billion, compared to $1.1 billion in the first nine months of 2000. The increase in operating cash flow in the first nine months of 2001 was primarily caused by the rise in revenues, partially offset by increased expenses, as discussed earlier in this section.

Devon used its operating cash flow and additional borrowings, net of repayments, to fund its capital expenditures and treasury stock repurchases during the first nine months of 2001.

Debt Securities

On October 3, 2001, Devon, through its wholly-owned financing subsidiary Devon Financing Corporation, U.L.C. ("Devon Financing"), sold $1.75 billion of 6.875% notes due September 30, 2011 and $1.25 billion of 7.875% debentures due September 30, 2031. The debt securities are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the Anderson acquisition.

The $3.0 billion of debt securities were structured in a manner that results in an expected weighted average after-tax borrowing rate of approximately 1.76%.

Interest on the debt securities will be payable by Devon Financing semiannually on March 30 and September 30 of each year, beginning on March 30, 2002. The indenture governing the debt securities limits both Devon Financing's and Devon's ability to incur liens or enter into mergers or consolidations, or transfer all or substantially all of their respective assets, unless the successor company assumes Devon Financing's or Devon's obligations under the indenture.

New Term Loan Credit Facility

On October 12, 2001, Devon and Devon Financing entered into a new $3.0 billion senior unsecured term loan credit facility arranged by UBS Warburg LLC and Banc of America Securities LLC. The facility has a term of five years. Devon and Devon Financing may borrow funds under this facility subject to conditions usual in commercial transactions of this nature. Interest on borrowings under this facility may be based, at the borrower's option, on the London Interbank Offered Rate ("LIBOR") or on UBS Warburg's base rate (which is the higher of UBS Warburg's prime commercial lending rate and the weighted average of rates on overnight Federal funds transactions with members of the Federal Reserve System plus 0.50%).

The interest rates will include a margin determined by Devon's long-term senior unsecured debt ratings. Notwithstanding the current debt ratings, the margin for borrowings based on LIBOR will be an additional 1.0% for the six-month period following completion of the syndication of this facility to a broader group of lenders, which is expected to occur in November 2001. Based on LIBOR rates as of October 30, 2001, Devon's rate would be 3.17%. In addition, the lenders under this facility will be charging Devon a per annum availability fee on their daily average unused lending commitments equal to a percentage determined by Devon's long-term senior unsecured debt rating.

On October 15, 2001, Devon used proceeds of $0.8 billion from borrowings on this facility, along with the $3.0 billion of proceeds from the debt securities referred to previously, to complete the Anderson acquisition, and to pay down Anderson's outstanding bank debt and other related fees and expenses. Devon expects substantially all of the remaining $2.2 billion of availability to be utilized upon the closing of the Mitchell acquisition. No borrowings under this facility may be made after September 13, 2002. As of October 31, 2001, Devon had approximately $2.2 billion available under its $3 billion term loan credit facility.

On a pro forma basis, assuming that $3.0 billion were drawn against this facility, the terms of this facility would require repayment of the debt during the following years:

	(billions)
2001	$ --
2002	$ --
2003	$ --
2007	$ 0.2
2008	$ 1.2
2009	$ 1.6

The terms of this facility also provide that voluntary prepayments of the debt are applied to the earliest scheduled maturities first. For example, if Devon were to prepay a portion of the $3.0 billion of debt with proceeds from property sales, the amount of the prepayment would reduce the amounts otherwise due first in 2004, then 2005 and finally 2006.

This credit facility contains certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio as defined in the credit facility.

Amendment of Existing Credit Facilities

On August 13, 2001, Devon renewed its 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").

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 $0.9 million that is payable quarterly.

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 August 12, 2002 (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. Debt borrowed under the Tranche B facility matures two years and one day following the end of the Tranche B Revolving Period. On September 30, 2001, there were no borrowings outstanding under the $725 million U.S. Facility.

Devon may borrow funds under the $275 million Canadian Facility until August 12, 2002 (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 45 and 90 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 semi annual 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, 2001, there was $60.2 million borrowed under the $275 million Canadian facility at an average interest rate of 3.9%. As of October 31, 2001, Devon had approximately $797 million available under its $1 billion credit facilities.

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.

The agreements governing the Credit Facilities contain certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio as defined in the agreements.

Commercial Paper

As of September 30, 2001, Devon had $129.8 million of borrowings under its commercial paper program at an average rate of 3.2%. Because Devon had the intent and ability to refinance the balance due with borrowings under its Credit Facilities, the $129.8 million outstanding under the commercial paper program was classified as long-term debt on the September 30, 2001 consolidated balance sheet.

Impact of Recently Issued Accounting Standards Not Yet Adopted. In July 2001, the FASB issued Statement No. 141, Business Combinations, and Statement No. 142, Goodwill and Other Intangible Assets. Statement 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001 as well as all purchase method business combinations completed after June 30, 2001. Statement 141 also specifies criteria intangible assets acquired in a purchase method business combination must meet to be recognized and reported apart from goodwill. Statement 142 will require that goodwill and intangible assets with indefinite useful lives no longer be amortized, but instead tested for impairment at least annually in accordance with the provisions of Statement 142. Statement 142 will also require that intangible assets with definite useful lives be amortized over their respective estimated useful lives to their estimated residual values, and reviewed for impairment in accordance with SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of.

Devon is required to adopt the provisions of Statement 141 immediately, and the provisions of Statement 142 effective January 1, 2002. Furthermore, any goodwill and any intangible asset determined to have an indefinite useful life that are acquired in a purchase business combination completed after June 30, 2001 will not be amortized, but will continue to be evaluated for impairment in accordance with the appropriate pre-Statement 142 accounting literature. Goodwill and intangible assets acquired in business combinations completed before July 1, 2001 will continue to be amortized prior to the adoption of Statement 142.

Statement 141 will require upon adoption of Statement 142, that Devon evaluate its existing goodwill that was acquired in a prior purchase business combination. In connection with the transitional goodwill impairment evaluation, Statement 142 will require Devon to perform an assessment of whether there is an indication that goodwill is impaired as of the date of adoption. To accomplish this Devon must identify its reporting units and determine the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill, to those reporting units as of the date of adoption. Devon will then have up to six months from the date of adoption to determine the fair value of each reporting unit and compare it to the reporting unit's carrying amount. To the extent a reporting unit's carrying amount exceeds its fair value, an indication exists that the reporting unit's goodwill may be impaired and Devon must perform the second step of the transitional impairment test. In the second step, Devon must compare the implied fair value of the reporting unit's goodwill, determined by allocating the reporting unit's fair value to all of it assets (recognized and unrecognized) and liabilities in a manner similar to a purchase price allocation in accordance with Statement 141, to its carrying amount, both of which would be measured as of the date of adoption. This second step is required to be completed as soon as possible, but no later than the end of the year of adoption. Any transitional impairment loss will be recognized as the cumulative effect of a change in accounting principle in Devon's statement of operations.

As of the date of adoption, Devon expects to have unamortized goodwill in the amount of $2.2 billion, including the effect of the Anderson acquisition, which will be subject to the transition provisions of Statements 141 and 142. If the Mitchell acquisition closes prior to December 31, 2001, Devon would expect to have $3.7 billion of unamortized goodwill at the date of adoption. Amortization expense related to goodwill was $41.3 million and $25.4 million for the year ended December 31, 2000 and the nine months ended September 30, 2001, respectively. Devon has not assessed the impact of adopting these Statements on Devon's financial statements at the date of this report, including whether any transitional impairment losses will be required to be recognized as the cumulative effect of a change in accounting principle.

Also in June 2001, the FASB issued Statement No. 143, Accounting for Asset Retirement

Obligations. Statement 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 Statement 143 are those for which a company faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be 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." Devon expects that it will use a valuation technique such as expected present value to estimate fair value.

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

Devon will be required to adopt Statement 143 effective January 1, 2003 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation.

Devon currently records estimated costs of dismantlement, removal, site reclamation, and other similar activities as part of depreciation, depletion, and amortization and does not record a separate liability for such amounts. Devon has not completed the assessment of the impact that adoption of Statement No. 143 will have on its consolidated financial statements. However, Devon expects the amounts for capitalized oil and gas property costs and asset retirement obligations will increase.

In August 2001, the Financial Accounting Standards Board issued FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (Statement 144), which supersedes both FASB Statement No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of (Statement 121) and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions (Opinion 30), for the disposal of a segment of a business (as previously defined in that Opinion). Statement 144 retains the fundamental provisions in Statement 121 for recognizing and measuring impairment losses on long-lived assets held for use and long-lived assets to be disposed of by sale, while also resolving significant implementation issues associated with Statement 121. For example, Statement 144 provides guidance on how a long-lived asset that is used as part of a group should be evaluated for impairment, establishes criteria for when a long-lived asset is held for sale, and prescribes the accounting for a long-lived asset that will be disposed of other than by sale. Statement 144 retains the basic provisions of Opinion 30 on how to present discontinued operations in the income statement but broadens that presentation to include a component of an entity (rather than a segment of a business). Unlike Statement 121, an impairment assessment under Statement 144 will never result in a write-down of goodwill. Rather, goodwill is evaluated for impairment under Statement No. 142, Goodwill and Other Intangible Assets.

Devon is required to adopt Statement 144 no later than the year beginning after December 15, 2001, and plans to adopt its provisions for the quarter ending March 31, 2002. Management does not expect the adoption of Statement 144 for long-lived assets held for use or for disposal to have a material impact on Devon's financial statements because Devon utilizes the full-cost method of accounting for oil and gas exploration and development activities and the impairment assessment under Statement 144 is largely unchanged from Statement 121.

Revisions to 2001 Estimates

On December 12, 2000, Devon filed a Form 8-K that provided forward-looking estimates for the year 2001. Full-year revisions of those previous estimates are provided herein. The revised estimates reflect the impact of Devon's acquisition of Anderson Exploration, Ltd. on October 15, 2001. The full-year revisions also include adjustments to previous estimates, when required, to reflect actual year-to-date results.

The revised forward-looking statements provided in this discussion are based on management's examination of historical operating trends, the information which was used to prepare the December 31, 2000 reserve reports of independent petroleum engineers and other data in Devon's possession or available from third parties. Devon cautions that its future oil, natural gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development and production and sale of oil and gas. These risks include, but are not limited to, price volatility, inflation, the lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. Also, the financial results of Devon's foreign operations are subject to currency exchange rate risks. Additional risks are discussed below in the context of line items most affected by such risks.

Specific Assumptions and Risks Related to Price and Production Estimates Prices for oil, natural gas and NGL are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and world-wide economic growth, weather and other substantially variable factors. These factors are beyond Devon's control and are difficult to predict. In addition to volatility in general, Devon's oil, gas and NGL prices may vary considerably due to differences between regional markets, transportation availability and demand for different grades of oil, gas and NGL. Substantially all of Devon's revenues are attributable to sales of these three commodities. Consequently, Devon's financial results and resources are highly influenced by this price volatility.

Estimates for Devon's future production of oil, natural gas and NGL are based on the assumption that market demand and prices for oil and gas will continue at levels that allow for profitable production of these products. There can be no assurance of such stability. Also, Devon's International production of oil, natural gas and NGL is governed by payout agreements with the governments of the countries in which Devon operates. If the payout under these agreements is attained earlier than projected, Devon's net production and proved reserves in such areas could be reduced.

The production, transportation and marketing of oil, natural gas and NGL are complex processes which are subject to disruption due to transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other factors. The following revised forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for Devon's oil, natural gas and NGL during the remainder of 2001 will be substantially similar to those of the first nine months of 2001, unless otherwise noted. Given the general limitations expressed herein, Devon's forward-looking statements for 2001 are set forth below. Unless otherwise noted, all of the following dollar amounts are expressed in U.S. dollars. Those amounts related to Canadian operations have been converted to U.S. dollars using an exchange rate of $0.6526 U.S. dollar to $1.00 Canadian dollar. The actual 2001 exchange rate may vary materially from this estimated rate. Such variations could have a material effect on the following Canadian estimates.

Geographic Reporting Areas for 2001 The following estimates of production, average price differentials and capital expenditures are provided separately for each of Devon's geographic divisions. These divisions are as follows:

o the Gulf Division, which operates oil and gas properties located primarily in the onshore South Texas and South Louisiana areas and offshore in the Gulf of Mexico;

o the Rocky Mountain Division, which operates oil and gas properties located in the Rocky Mountains area of the United States stretching from the Canadian border south into northern New Mexico;

o the Permian/Mid-Continent Division, which operates all properties located in the United States other than those operated by the Gulf Division and the Rocky Mountain Division

o Canada; and

o International Division, which encompasses all oil and gas properties that lie outside of the United States and Canada.

2001 POTENTIAL OPERATING ITEMS

Oil, Gas and NGL Production Set forth in the following paragraphs are individual estimates of Devon's oil, gas and NGL production for 2001. On a combined basis, Devon estimates its 2001 oil, gas and NGL production will total between 132.5 million and 136.2 million barrels of oil equivalent. Devon's estimates of 2001 production do not include certain oil, gas and NGL production from various properties that were sold during 2000. These sold properties produced approximately 2.9 million barrels of oil equivalent in 2000 that will not be produced by Devon in 2001.

Oil Production Devon expects its oil production in 2001 to total between 43.4 million barrels and 44.5 million barrels. The expected ranges of production by division are as follows:

	Expected Range of Production (MMBbls)
Permian/Mid-Continent	12.9 to 13.1
Gulf	10.8 to 11.0
Rocky Mountain	2.1 to 2.3
Canada	8.0 to 8.3
International	9.6 to 9.8

Oil Prices - Fixed Devon has fixed the price it will receive in 2001 on a portion of its oil production through certain forward oil sales. These forward oil sales are attributable to the Permian/Mid-Continent Division and total 3.7 million barrels at an average price of $16.84 per barrel. Santa Fe Snyder Corporation entered into these forward oil sales agreements in late 1999 and early 2000, and used the proceeds to acquire interests in producing properties in the Gulf of Mexico.

For the fourth quarter of 2001, Devon has executed price swaps attributable to the Permian/Mid-Continent Division for 1.4 million barrels at an average price of $27.10 per barrel. Additionally, for the fourth quarter of 2001, Devon has entered into price swaps attributable to Canada for 0.5 million barrels at an average price of $21.52 per barrel.

Oil Prices - Floating For the oil production for which prices have not been fixed, Devon's 2001 average prices for each of its divisions are expected to differ from the New York Mercantile Exchange price ("NYMEX") 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.

	Expected Range of Oil Prices Greater Than (Less Than) NYMEX
Permian/Mid-Continent	($4.15) to ($3.15)
Gulf	($3.20) to ($2.20)
Rocky Mountain	($2.15) to ($1.15)
Canada	($7.50) to ($6.50)
International	($3.60) to ($2.60)

The above range of expected Canadian differentials compared to NYMEX includes an estimated $0.07 per barrel decrease resulting from foreign currency hedges. These hedges, in which Devon will sell $10 million in 2001 at an average Canadian-to-U.S. exchange rate of $0.710 and buy the same amount of dollars at the floating exchange rate, offset a portion of the exposure to currency fluctuations on those Canadian oil sales that are based on U.S. prices. The

$0.07 per barrel decrease is based on the assumption that the average Canadian-to-U.S. conversion rate for the year 2001 is $0.6526.

Gas Production Devon expects its 2001 gas production to total between 493 Bcf and 505 Bcf. The expected ranges of production by division are as follows:

	Expected Range of Production (Bcf)
Permian/Mid-Continent	121 to 123
Gulf	143 to 145
Rocky Mountain	112 to 114
Canada	109 to 113
International	8 to 10

Gas Prices - Fixed Through various price swaps and fixed-price physical delivery contracts, Devon has fixed the price it will receive in 2001 on a portion of its natural gas production. The following tables include information on this fixed-price production by division. Where necessary, the prices 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.

	First Nine Months of 2001		Fourth Quarter of 2001	
Division	Mcf/Day	Price/Mcf	Mcf/Day	Price/Mcf
Permian/Mid-Continent	674	$ 1.94	2,000	$ 1.94
Rocky Mountain	33,231	$ 2.95	54,475	$ 3.30
Gulf	14,491	$ 5.17	155,935	$ 3.46
Canada	58,960	$ 1.53	87,348	$ 1.78

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2001 natural gas production. The following tables include information on these collars for each division. The floor and ceiling prices related to domestic production are based on various regional first-of-the-month price indices as published monthly by "Inside F.E.R.C.'s Gas Market Report" ("Inside FERC"). The floor and ceiling prices related to Canadian production are based on the AECO index as published by the "Canadian Gas Price Reporter."

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 content of gas production, 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 floor and ceiling prices in the following table are weighted averages of all the various collars.

	First Nine Months of 2001			Fourth Quarter of 2001		
Division	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu
Permian/Mid-Continent	--	$ --	$ --	50,000	$ 2.91	$ 4.42
Rocky Mountain	6,740	$ 4.10	$ 8.10	20,000	$ 4.10	$ 8.10
Gulf	--	$ --	$ --	140,652	$ 2.95	$ 4.01
Canada	--	$ --	$ --	18,964	$ 2.58	$ 3.89

Additionally, Devon has entered into a basis swap on 7.3 Bcf of 2001 gas production. Under the terms of the basis swap, the counterparty pays Devon the average NYMEX price for the last three trading days of each month, less $0.30 per Mcf. In return, Devon pays the counterparty the Colorado Interstate Gas Co. ("CIG") index price published by Inside FERC. The effect of this swap is included in Rocky Mountain Division gas revenues. This basis swap does not qualify as a hedge under the provisions of SFAS No. 133. Accordingly, fluctuations in the fair value of this basis swap have been recorded in earnings throughout 2001.

Gas production in Argentina of 8 Bcf to 9 Bcf will be sold at a fixed price of approximately $1.39 per Mcf.

Gas Prices - Floating For the natural gas production for which prices have not been fixed, Devon's 2001 average prices for each of its divisions are expected to differ from NYMEX as set forth in the following table. NYMEX is determined to be the first-of-month South Louisiana Henry Hub price index as published monthly in Inside FERC.

	Expected Range of Gas Prices Greater Than (Less Than) NYMEX
Permian/Mid-Continent	($0.55) to ($0.05)
Gulf	$0.35 to $0.85
Rocky Mountain	($0.90) to ($0.40)
Canada	($1.35) to ($0.85)
International	($2.70) to ($2.20)

NGL Production Devon expects its 2001 production of NGL to total between 6.9 million barrels and 7.5 million barrels. The expected ranges of production by division are as follows:

	Expected Range of Production (MMBbls)
Permian/Mid-Continent	3.6 to 3.8
Gulf	1.2 to 1.3
Rocky Mountain	0.6 to 0.7
Canada	1.4 to 1.5
International	0.1 to 0.2

Other Revenues Devon's other revenues in 2001 are expected to be between $87 million and $90 million.

Production and Operating Expenses Devon's 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 expense and impact the economic feasibility of planned workover projects.

These factors, coupled with uncertainty of future oil, natural gas and NGL prices, increase the uncertainty inherent in estimating future production and operating costs. Given these uncertainties, Devon estimates that year 2001 lease operating expenses will be between $526 million and $537 million, transportation costs will be between $76 million and $78 million and production taxes will be between 3.70% and 4.20% of consolidated oil, natural gas and NGL revenues.

Depreciation, Depletion and Amortization ("DD&A") The 2001 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 2001 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2000 reserve estimates that, based on prior experience, are likely to be made during 2001.

This range of full-year DD&A rates should result in oil and gas property related DD&A expense for 2001 of between $805 million and $821 million. Additionally, Devon expects its 2001 DD&A expense related to non-oil and gas property fixed assets to total between $35 million and $39 million. Based on these DD&A amounts and the production estimates discussed earlier, Devon expects its consolidated DD&A rate will be between $6.25 per Boe and $6.45 per Boe.

In addition to its oil and gas property DD&A expense and its non-oil and gas property fixed asset DD&A expense, Devon also expects to record goodwill amortization in 2001 of between $33 million and $34 million. The goodwill was recorded in connection with the 1999 merger with PennzEnergy. The goodwill recorded in connection with the 2001 Anderson acquisition is not subject to amortization.

General and Administrative Expenses ("G&A") Devon's G&A includes the costs of many different goods and services used in support of its business. These goods and services are subject to general price level increases or decreases. In addition, Devon's G&A varies with its level of activity and the related staffing needs as well as with the amount of professional services required during any given period. Should Devon's needs or the prices of the required goods and services differ significantly from current expectations, actual G&A could vary materially from the estimate. Given these limitations, consolidated G&A in 2001 is expected to be between $102 million and $106 million.

Interest Expense Future interest rates and oil, natural gas and NGL prices have a significant effect on Devon's interest expense. Approximately $1.8 billion of Devon's September 30, 2001, long-term debt balance of $2.0 billion bears interest at fixed rates. In October 2001, Devon sold $3 billion of debt securities and drew down $0.8 billion on its new $3 billion term loan credit facility. The interest rate on the debt securities is fixed, while the interest rate on the term loan credit facility is floating. Fixed rates remove the uncertainty of future interest rates from some, but not all, of Devon's long-term debt. Devon can only marginally influence the prices it will receive in 2001 from sales of oil, natural gas and NGL 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. Given the uncertainty of future interest rates and commodity prices, and assuming that the fixed-rate debt remains in place throughout the remainder of the year and no further draws are made on the $3 billion term loan credit facility, Devon estimates that consolidated interest expense in 2001 will be between $210 million and $214 million.

Reduction of Carrying Value of Oil and Gas Properties As of October 31, 2001, the ceiling for each full cost pool exceeded Devon's carrying value of oil and natural gas properties, less deferred income taxes. However, due to volatility in oil and gas prices and the effect of the Anderson and Mitchell acquisitions, there is a possibility that a reduction in the carrying value of oil and gas properties would be required as of December 31, 2001 or in future periods.

During the first nine months of 2001, Devon elected to discontinue operations in Thailand, Malaysia, Qatar and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, Devon determined that these properties did not meet Devon's internal criteria to justify further investment. Accordingly, during the first nine months of 2001, Devon recorded an $87.9 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $68.8 million.

Income Taxes Devon expects its consolidated financial income tax rate in 2001 to be between 35% and 45%. The current income tax rate is expected to be between 10% and 15%. The deferred income tax rate is expected to be between 25% and 30%. There are certain items that will have a fixed impact on 2001's income tax expense regardless of the level of pre-tax earnings that are produced. These items include Section 29 tax credits in the U.S., which reduce income taxes based on production levels of certain properties and are not necessarily affected by pre-tax financial earnings. The amount of Section 29 tax credits expected to be generated to offset financial income tax expense in 2001 is approximately $25 million. Also, Devon's Canadian subsidiaries are subject to Canada's "large corporation tax" of approximately $4 million which is based on total capitalization levels, not pre-tax earnings. The financial income tax in 2001 will also be increased by approximately $13 million due to the financial amortization of certain costs, such as goodwill amortization, that are not deductible for income tax purposes. Significant changes in estimated production levels of oil, gas and NGL, the prices of such products, or any of the various expense items could materially alter the effect of the aforementioned items on 2001's financial income tax rates.

2001 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. However, Devon expects to spend approximately $4.1 billion on acquisitions in 2001 including the Anderson acquisition. If the Mitchell acquisition closes prior to December 31, 2001, Devon would spend an additional $1.6 billion on acquisitions in 2001.

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 Devon's price expectations for its future production change significantly, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2001 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 2001 capital expenditures for drilling and development efforts plus related facilities to total between $1.25 billion and $1.31 billion. These amounts include between $390 million and $410 million for drilling and facilities costs related to reserves classified as proved as of December 31, 2000. In addition, these amounts include between $465 million and $485 million for other low risk/reward projects and between $395 million and $415 million for new, higher risk/reward projects. Low risk/reward projects include development drilling that do not offset currently productive units and 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 major operating division.

	Drilling and Production Facilities Expenditures (millions)				
	Rocky Mountain Division	Permian/ Mid-Continent Division	Gulf Division	Canada	Other International
Related to Proved Reserves	$75-$85	$70-$80	$65-$75	$80-$90	$80-$100
Lower Risk/Reward Projects	$60-$70	$115-$125	$165-$185	$80-$90	$20-$30
Higher Risk/Reward Projects	$10-$20	$45-$55	$110-$120	$135-$155	$75-$85
Total	$145-$175	$230-$260	$340-$380	$295-$335	$175-$215

In addition to the above expenditures for drilling and development, Devon is participating through a joint venture in the construction of gas transportation and processing systems in the Powder River Basin of Wyoming. Devon expects to spend from $35 million to $40 million as its share of the project in 2001. Devon also expects to capitalize between $75 million and $85 million of G&A expenses in accordance with the full-cost method of accounting. Devon also expects to pay between $15 million and $20 million for plugging and abandonment charges in 2001. Finally, Devon expects to spend between $15 million and $20 million for non-oil and gas property fixed assets.

Other Cash Uses Devon's management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.05 per share quarterly dividend rate and 128 million shares of average common stock outstanding for the year, 2001 dividends are expected to approximate $26 million. Also, Devon has $150 million of 6.49% cumulative preferred stock upon which it will pay $9.7 million of dividends in 2001.

Capital Resources and Liquidity Devon's estimated 2001 cash uses, including its drilling and development activities, are expected to be funded primarily through a combination of working capital and operating cash flow, with the remainder, if any, funded with borrowings from Devon's Credit Facilities. The amount of operating cash flow to be generated during 2001 is uncertain due to the factors affecting revenues and expenses as previously cited. However, Devon expects its combined capital resources to be more than adequate to fund its anticipated capital expenditures and other cash uses for 2001. As of October 31, 2001, Devon had $797 million available under its $1 billion Credit Facilities.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about Devon's potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and gas prices, interest rates and foreign currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how Devon views and manages its ongoing market risk exposures. All of Devon's market risk sensitive instruments were entered into for purposes other than trading.

Commodity Price Risk Devon's major market risk exposure is in the pricing applicable to its oil and gas 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 production. Pricing for oil and gas 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 trading purposes.

Devon's total hedged positions as of October 31, 2001 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 2001, 2002 and 2003. The following tables include information on this production. Where necessary, the prices 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

Division	First Nine Months of 2001 Bbls/Day	First Nine Months of 2001 Price/Bbl	Fourth Quarter of 2001 Bbls/Day	Fourth Quarter of 2001 Price/Bbl
Permian/Mid-Continent	--	$ --	15,000	$ 27.10
Canada	--	$ --	5,859	$ 21.52

Division	First Half of 2002 Bbls/Day	First Half of 2002 Price/Bbl	Second Half of 2002 Bbls/Day	Second Half of 2002 Price/Bbl
Gulf	22,000	$ 23.85	22,000	$ 23.85
Canada	4,350	$ 20.33	4,350	$ 20.33

GAS PRODUCTION

Division	First Nine Months of 2001 Mcf/Day	First Nine Months of 2001 Price/Mcf	Fourth Quarter of 2001 Mcf/Day	Fourth Quarter of 2001 Price/Mcf
Permian/Mid-Continent	674	$ 1.94	2,000	$ 1.94
Rocky Mountain	33,231	$ 2.95	54,475	$ 3.30
Gulf	14,491	$ 5.17	155,935	$ 3.46
Canada	18,431	$ 1.60	23,491	$ 1.89

Division	First Half of 2002 Mcf/Day	First Half of 2002 Price/Mcf	Second Half of 2002 Mcf/Day	Second Half of 2002 Price/Mcf
Permian/Mid-Continent	50,343	$ 2.80	50,000	$ 2.81
Rocky Mountain	36,495	$ 2.86	39,007	$ 2.81
Gulf	110,514	$ 3.21	110,000	$ 3.22
Canada	40,589	$ 2.10	33,427	$ 2.13

Division	First Half of 2003 Mcf/Day	First Half of 2003 Price/Mcf	Second Half of 2003 Mcf/Day	Second Half of 2003 Price/Mcf
Gulf	80,000	$ 3.42	80,000	$ 3.42
Canada	5,000	$ 2.31	5,000	$ 2.21

Costless Price Collars Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2001, 2002 and 2003 oil and natural gas production. The following tables include information on these collars for each division. The floor and ceiling prices related to domestic oil production are based on NYMEX. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. The floor and ceiling prices related to domestic gas production are based on various regional first-of-the-month price indices as published monthly by Inside FERC. The floor and ceiling prices related to Canadian production are based on the AECO index as published by the "Canadian Gas Price Reporter."

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 content of gas production, 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 floor and ceiling prices in the following tables are weighted averages of all the various collars.

OIL PRODUCTION

	First Half of 2002			Second Half of 2002		
Division	Bbls/Day	Floor Price Per Bbl	Ceiling Price Per Bbl	Bbls/ Day	Floor Price Per Bbl	Ceiling Price Per Bbl
Permian/Mid-Continent	18,450	$ 23.00	$ 28.18	18,450	$ 23.00	$ 28.18
Gulf	1,550	$ 23.00	$ 28.33	1,550	$ 23.00	$ 28.33

GAS PRODUCTION

	First Nine Months of 2001			Fourth Quarter of 2001		
Division	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	MMBtu /Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu
Permian/Mid-Continent	--	$ --	$ --	50,000	$ 2.91	$ 4.42
Rocky Mountain	6,740	$ 4.10	$ 8.10	20,000	$ 4.10	$ 8.10
Gulf	--	$ --	$ --	140,652	$ 2.95	$ 4.01
Canada	--	$ --	$ --	18,964	$ 2.58	$ 3.89

	First Half of 2002			Second Half of 2002		
Division	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	MMBtu /Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu
Permian/Mid-Continent	131,800	$ 3.27	$ 6.17	81,800	$ 3.49	$ 7.25
Rocky Mountain	105,000	$ 2.98	$ 7.01	105,000	$ 2.98	$ 7.01
Gulf	178,200	$ 3.23	$ 5.98	98,200	$ 3.49	$ 7.23
Canada	42,670	$ 2.87	$ 5.16	23,705	$ 3.09	$ 6.17

Division	First Half of 2003			Second Half of 2003		
	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	MMBtu/ Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu
Permian/Mid-Continent	100,000	$ 3.07	$ 4.00	100,000	$ 3.07	$ 4.00
Rocky Mountain	20,000	$ 2.74	$ 3.95	20,000	$ 2.74	$ 3.95
Gulf	125,000	$ 3.13	$ 4.23	125,000	$ 3.13	$ 4.23
Canada	80,000	$ 2.82	$ 3.62	80,000	$ 2.82	$ 3.62

Basis Swap Devon has entered into a basis swap on 20,000 MMBtu of gas production per day that expires at the end of August 2004. Under the terms of the basis swap, the counterparty pays Devon the average NYMEX price for the last three trading days of each month, less $0.30, per MMBtu. In return, Devon pays the counterparty the CIG index price published by Inside FERC. The effect of this swap is included in Rocky Mountain Division gas revenues. This basis swap does not qualify as a hedge under the provisions of SFAS No. 133. Accordingly, fluctuations in the fair value of this basis swap have been recorded in earnings throughout 2001.

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 31, 2001, a 10% increase in the underlying commodities' prices would have reduced the fair value of Devon's commodity hedging instruments by $105.7 million.

Fixed-Price Physical Delivery Contracts In addition to the commodity hedging instruments described above, Devon also manages its exposure to oil and gas price risks by periodically entering into fixed-price contracts.

Devon has fixed the price it will receive on a portion of its 2001 and 2002 oil production through certain forward oil sales. From January 2001 through August 2002, 311,000 barrels of oil production per month have been fixed at an average price of $16.84 per barrel. These fixed-price barrels are attributable to the Permian/Mid-Continent Division.

For each of the years 2001 through 2011, Devon has fixed-price gas contracts that cover approximately 17 Bcf, 24 Bcf, 19 Bcf, 19 Bcf, 19 Bcf, 19 Bcf, 17 Bcf, 16 Bcf, 16 Bcf, 15 Bcf and 13 Bcf, respectively, of Canadian production. 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.

Interest Rate Risk At September 30, 2001, Devon had long-term debt outstanding of $2.0 billion. Of this amount, $1.8 billion, or 90%, bears interest at fixed rates averaging 5.8%. The remaining $0.2 billion of debt outstanding bears interest at floating rates which averaged

3.9%. In October 2001, Devon sold $3 billion of debt securities and drew down $0.8 billion on its new $3 billion term loan credit facility to fund the Anderson acquisition. The interest rate on the debt securities is fixed at a weighted average rate of 7.4%. The interest rate on the term loan credit facility is floating.

At September 30, 2001, Devon had entered into interest rate locks to reduce exposure to the variability in market interest rates, specifically U.S. Treasury rates, in anticipation of the sale of the $3 billion of debt securities. Effective October 3, 2001, these interest rate locks were settled and the $28.7 million loss incurred on these derivative instruments was recorded in Accumulated Other Comprehensive Loss and will be amortized into interest expense using the effective interest rate method over the life of the debt securities.

The terms of the various floating rate debt facilities (Credit Facilities, commercial paper and term loan credit facility) allow interest rates to be fixed at Devon's option for periods of between 7 to 180 days. A 10% increase in short-term interest rates on the floating-rate debt outstanding as of September 30, 2001, as adjusted for the new floating rate debt drawn down in October 2001, would equal approximately 34 basis points. Such an increase in interest rates would increase Devon's fourth quarter 2001 interest expense by approximately $0.9 million assuming borrowed amounts remain outstanding for the remainder of 2001.

Devon assumed certain interest rate swaps as a result of the Anderson acquisition. Under these interest rate swaps, Devon has swapped a floating rate for a fixed rate. Under such swaps, Devon will record a fixed rate of 6.1% on $108.1 million of debt in the fourth quarter of 2001 and on $128.3 million in 2002. Devon will record a fixed rate of 6.2% on $96.8 million of debt in 2003, and 6.3% on $78.5 million of debt in 2004 through 2006 and on $31.0 million 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 October 31, 2001, a 10% increase in the underlying interest rates would have increased the fair value of Devon's interest rate swaps by $2.7 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 net assets, net earnings and cash flows from its Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the applicable functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period.

As a result of the Anderson acquisition, Devon has $400 million of fixed-rate long-term debt that is denominated in U.S. dollars. Changes in the currency conversion rate between the Canadian and U.S. dollars between the beginning and end of a reporting period increase or decrease the expected amount of Canadian dollars required to repay the notes. The amount of such increase or decrease is required to be included in determining net earnings for the period in which the exchange rate changes. The only principal payments on these notes are not due until 2011. Until then, the gains or losses caused by the exchange rate fluctuations have no effect on cash flow. In the fourth quarter of 2001, a $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would cause Devon to record a charge of approximately $19 million.

Substantially all of Devon's Canadian oil sales are paid in Canadian dollars, but at amounts based on the U.S. dollar price of oil. Therefore, currency fluctuations between the Canadian and U.S. dollars impact the amount of Canadian dollars received by Devon's Canadian subsidiaries for their oil production. To mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on Canadian oil revenues, Devon has existing foreign currency exchange rate swaps. Under such swap agreements, in 2001 Devon will sell $10 million at an average Canadian-to-U.S. exchange rate of $0.710 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 oil sales. At the year-end 2000 exchange rate, these swaps would result in decreases to 2001's annual oil sales of approximately $0.6 million. A further $0.03 decrease in the Canadian-to-U.S. dollar exchange rate in 2001 would result in an additional decrease in oil sales of approximately $0.4 million.

Also, at September 30, 2001, Devon had entered into foreign exchange forward contracts to mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on the Anderson acquisition. Effective October 15, 2001, these contracts were settled for a gain of $30 million. The gain was recorded in the statement of operations as part of other income.

Devon assumed certain foreign currency exchange rate swaps in the Anderson acquisition. These swaps require Devon to sell $10.1 million at an average Canadian-to-U.S. exchange rate of $0.663, and buy the same amount of dollars at the floating exchange rate in the fourth quarter of 2001. These swaps also require Devon to sell $30 million and $12 million at average Canadian-to-U.S. exchange rates of $0.680 and $0.676, and buy the same amount of dollars at the floating exchange rate, in 2002 and 2003, respectively. The amount of gains or losses realized from such swaps are included as increases or decreases to realized gas sales. At the October 31, 2001 exchange rate, these swaps would result in a decrease to gas sales during the fourth quarter of 2001 of approximately $3.9 million. A further $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would result in an additional decrease to gas sales of approximately $4.6 million.

For purposes of the sensitivity analysis described above for changes in the Canadian dollar exchange rate, a change in the rate of $0.03 was used as opposed to a 10% change in the rate. During the last eight years, the Canadian-to-U.S. dollar exchange rate has fluctuated an average of approximately 4% per year, and no year's fluctuation was greater than 7%. The $0.03

change used in the above analysis represents an approximate 4% change in the year-end 2000 rate.

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

Item 6. Exhibits and Reports on Form 8-K

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

Exhibit No.	
2.1	Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Devon Energy Corporation, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (attached as Annex A to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001)
2.2	Pre-Acquisition Agreement, dated as of August 31, 2001, between Devon Energy Corporation and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Devon Energy Corporation Amendment No. 1 to Form S-4 Registration Statement No. 333-68694 as filed September 14, 2001)

Exhibit No.	
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4.2	Amendment to Rights Agreement, dated as of May 25, 2000, by and between Devon Energy Corporation and Fleet National Bank (f/k/a BankBoston, N.A.) (incorporated by reference to Exhibit 4.2 to Devon Energy Corporation's definitive proxy statement for a special meeting of shareholders filed on July 21, 2000)
4.3	Amendment to Rights Agreement, dated as of October 4, 2001, by and between Devon Energy Corporation and Fleet National Bank (f/k/a Bank Boston, N.A.) (incorporated by reference to Exhibit 99.1 to Devon Energy Corporation's Form 8-K filed on October 11, 2001)
4.4	Description of Capital Stock of Devon Energy Corporation (incorporated by reference to Exhibit 4.9 to Devon Energy Corporation's Form 8-K filed on August 18, 1999)
4.5	Indenture, dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. (as issuer), Devon Energy Corporation (as guarantor) and The Chase Manhattan Bank (as trustee) (incorporated by reference to Exhibit 4.7 to Devon Energy Corporation Amendment No. 2 to Form S-4 Registration Statement No. 333-68694 as filed October 31, 2001)

Exhibit No.	
4.6	Registration Rights Agreement dated as of October 3, 2001 by and among Devon Financing Corporation, U.L.C., as Issuer, Devon Energy Corporation, as Guarantor and UBS Warburg LLC, Banc of America Securities LLC, ABN AMRO Incorporated, BMO Nesbitt Burns Corp., Credit Suisse First Boston Corporation, Deutsche Banc Alex. Brown Inc., First Union Securities, Inc., J.P. Morgan Securities Inc., RBC Dominion Securities Corporation, Salomon Smith Barney Inc., as Initial Purchasers (6.875% Notes due 2011, 7.875% Debentures due 2031) (incorporated by reference to Exhibit 4.8 to Devon Energy Corporation Amendment No. 2 to Form S-4 Registration Statement No. 333-68694 as filed October 31, 2001)
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(b) Reports on Form 8-K - Reports on Form 8-K filed since July 1, 2001, are described below:

Filing Date	Contents
September 20, 2001	Press release concerning proposal to issue $3 billion of senior notes through a private placement.
September 26, 2001	Press release updating oil and gas hedging positions.
September 27, 2001	Press release announcing the proposed amendment of the merger agreement to eliminate the risk that Devon's stock price would prevent issuance of tax opinions that are a condition to the Mitchell transaction.
October 3, 2001	Press release concerning completion of the private placement of $3 billion of senior notes.
October 11, 2001	Announcement of the amendment of various documents related to the Mitchell acquisition.
October 12, 2001	Press release announcing the acceptance by the Anderson shareholders of the cash tender offer.
October 26, 2001	Announcement of the completion of the Anderson acquisition.
October 31, 2001	Press release updating oil and gas hedging positions.
November 1, 2001	Press release announcing third quarter earnings and results.
November 1, 2001	Financial statements and notes thereto of Devon as of September 30, 2001 and for the three-month and nine-month periods ended September 30, 2001 and 2000.

SIGNATURES

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

DEVON ENERGY CORPORATION

Date: November 14, 2001	*/s/ Danny J. Heatly* -------------------------------- *Danny J. Heatly* *Vice President - Accounting*

INDEX TO EXHIBITS

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