VINTAGE PETROLEUM INC
Form 10-Q
August 08, 2003

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 June 30, 2003

OR

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

For the transition period from______ to ______

Commission file number 1-10578

VINTAGE PETROLEUM, INC.

(Exact name of registrant as specified in charter)

Delaware	**73-1182669**
(State or other jurisdiction of	**(I.R.S. Employer**

incorporation or organization)	**Identification No.)**
110 West Seventh Street	**74119-1029**
Tulsa, Oklahoma	**(Zip Code)**
(Address of principal executive offices)	

(918) 592-0101

(Registrant s telephone number, including area code)

NOT APPLICABLE

(Former name, former address and former fiscal year, if changed since 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 ¨

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

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date.

Class	Outstanding at July 31, 2003
Common Stock, $.005 Par Value	64,257,637

PART I

FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except shares

and per share amounts)

	June 30, 2003 (Unaudited)	December 31, 2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 106,816	$ 9,259
Accounts receivable -		
Oil and gas sales	104,578	90,267
Joint operations	7,946	9,542
Prepaids and other current assets	20,722	21,021
Assets of discontinued operations		86,174
Total current assets	240,062	216,263
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method	2,619,037	2,487,549
Oil and gas gathering systems and plants	22,627	20,588
Other	27,939	26,501
	2,669,603	2,534,638
Less accumulated depreciation, depletion and amortization	1,092,177	1,047,665
Total property, plant and equipment, net	1,577,426	1,486,973
GOODWILL	24,702	21,099
OTHER ASSETS, net	48,241	51,469
TOTAL ASSETS	$ 1,890,431	$ 1,775,804

See notes to unaudited consolidated financial statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Continued)

(In thousands, except shares

and per share amounts)

	June 30, 2003	December 31, 2002
	(Unaudited)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Revenue payable	$ 32,097	$ 30,869
Accounts payable - trade	35,136	42,038
Current income taxes payable	43,858	18,722
Short-term debt	3,396	4,732
Derivative financial instruments payable	19,708	17,122
Other payables and accrued liabilities	56,401	54,281
Liabilities of discontinued operations		10,769
Total current liabilities	190,596	178,533
LONG-TERM DEBT	802,535	883,180
DEFERRED INCOME TAXES	137,479	137,015
LONG-TERM LIABILITY FOR ASSET RETIREMENT OBLIGATIONS	83,176	
OTHER LONG-TERM LIABILITIES	4,488	6,084
COMMITMENTS AND CONTINGENCIES (Note 6)		
STOCKHOLDERS EQUITY, per accompanying statement:		
Preferred stock, $.01 par, 5,000,000 shares authorized, zero shares issued and outstanding		
Common stock, $.005 par, 160,000,000 shares authorized, 64,312,375 and 63,432,972 shares issued and 64,039,787 and 63,348,272 outstanding, respectively	321	317
Capital in excess of par value	334,644	326,510
Retained earnings	301,527	274,971
Accumulated other comprehensive income (loss)	44,316	(28,573)
	680,808	573,225
Less treasury stock, at cost, 272,588 and 84,700 shares, respectively	1,295	
Less unamortized cost of restricted stock awards	7,356	2,233
Total stockholders equity	672,157	570,992
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 1,890,431	$ 1,775,804

See notes to unaudited consolidated financial statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
REVENUES:				
Oil and gas sales	$ 159,521	$ 152,673	$ 345,179	$ 271,172
Gas marketing	26,741	17,405	59,661	29,733
Oil and gas gathering and processing	1,556	1,468	3,510	2,853
Gain (loss) on disposition of assets	305	17,624	(345)	17,709
Foreign currency exchange gain (loss)	(3,514)	1,209	(7,151)	4,101
Other income	2,204	576	1,955	1,193
Total revenues	186,813	190,955	402,809	326,761
COSTS AND EXPENSES:				
Lease operating, including production and export taxes	54,320	53,904	108,530	100,757
Exploration costs	32,449	7,002	46,527	15,956
Gas marketing	26,386	16,941	58,423	28,745
Oil and gas gathering and processing	1,794	1,505	4,390	3,282
General and administrative	15,868	12,546	30,274	25,060
Depreciation, depletion and amortization	34,783	46,076	72,077	95,317
Impairment of oil and gas properties	12,571		12,571	
Accretion	1,832		3,579	
Interest	18,016	20,741	36,557	38,178
Loss on early extinguishment of debt		8,154	1,426	8,154
Total costs and expenses	198,019	166,869	374,354	315,449
Income (loss) from continuing operations before income taxes and cumulative effect of changes in accounting principles	(11,206)	24,086	28,455	11,312
PROVISION (BENEFIT) FOR INCOME TAXES:				
Current	16,369	9,755	30,832	11,794
Deferred	(18,888)	(6,491)	(16,408)	(15,009)
Total provision (benefit) for income taxes	(2,519)	3,264	14,424	(3,215)
	(8,687)	20,822	14,031	14,527

Income (loss) from continuing operations before cumulative effect of changes in accounting principles				
INCOME FROM DISCONTINUED OPERATIONS, net of income taxes		1,607	10,844	2,282
Income (loss) before cumulative effect of changes in accounting principles	(8,687)	22,429	24,875	16,809
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, net of income tax provision of zero, zero, $4,104 and zero, respectively			7,119	(60,547)
NET INCOME (LOSS)	$ (8,687)	$ 22,429	$ 31,994	$ (43,738)

See notes to unaudited consolidated financial statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Continued)

(In thousands, except per share amounts)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
BASIC INCOME (LOSS) PER SHARE:				
Income (loss) from continuing operations before cumulative effect of changes in accounting principles	$ (0.14)	$ 0.33	$ 0.22	$ 0.23
Income from discontinued operations		0.03	0.17	0.04
Income (loss) before cumulative effect of changes in accounting principles	(0.14)	0.36	0.39	0.27
Cumulative effect of changes in accounting principles			0.11	(0.96)
Net income (loss)	$ (0.14)	$ 0.36	$ 0.50	$ (0.69)
DILUTED INCOME (LOSS) PER SHARE:				
Income (loss) from continuing operations before cumulative effect of changes in accounting principles	$ (0.14)	$ 0.33	$ 0.21	$ 0.23
Income from discontinued operations		0.02	0.17	0.04
Income (loss) before cumulative effect of changes in accounting principles	(0.14)	0.35	0.38	0.27
Cumulative effect of changes in accounting principles			0.11	(0.95)
Net income (loss)	$ (0.14)	$ 0.35	$ 0.49	$ (0.68)
Weighted average common shares outstanding:				
Basic	63,991	63,128	63,791	63,102
Diluted	63,991	63,925	65,120	63,858

See notes to unaudited consolidated financial statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

FOR THE SIX MONTHS ENDED JUNE 30, 2003

(In thousands, except per share amounts)

(Unaudited)

	Common Stock		Treasury Stock		Capital In Excess of Par Value	Unamortized Restricted Stock Awards	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount	Shares	Amount					
BALANCE AT DECEMBER 31, 2002	63,433	$ 317	85	$	$ 326,510	$ (2,233)	$ 274,971	$ (28,573)	$ 570,992
Comprehensive income:									
Net income							31,994		31,994
Foreign currency translation adjustment								75,698	75,698
Change in value of derivatives, net of tax								(2,809)	(2,809)
Total comprehensive income									104,883
Exercise of stock options and resulting tax effects	79				581				581
Issuance of restricted stock	800	4			7,946	(7,950)			
Amortization of restricted stock awards					340	2,231			2,571
Forfeiture of restricted stock and other			72		(733)	596			(137)
Purchase of treasury stock			116	(1,295)					(1,295)
Cash dividends declared ($0.085 per share)							(5,438)		(5,438)
BALANCE AT JUNE 30, 2003	64,312	$ 321	273	$ (1,295)	$ 334,644	$ (7,356)	$ 301,527	$ 44,316	$ 672,157

See notes to unaudited consolidated financial statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Six Months Ended June 30,	
	2003	**2002**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 31,994	$ (43,738)
Adjustments to reconcile net income (loss) to cash provided by operating activities -		
Income from discontinued operations, net of tax	(10,844)	(2,282)
Cumulative effect of changes in accounting principles	(7,119)	60,547
Depreciation, depletion and amortization	72,077	95,317
Impairment of oil and gas properties	12,571	
Accretion expense	3,579	
Exploration costs	46,527	15,956
Benefit for deferred income taxes	(16,408)	(15,009)
Foreign currency exchange (gain) loss	7,151	(4,101)
(Gain) loss on dispositions of assets	345	(17,709)
Loss on early extinguishment of debt	1,426	8,154
Other non-cash items	2,716	435
	144,015	97,570
Increase in receivables	(10,421)	(14,620)
Decrease in payables and accrued liabilities	(20,107)	(6,489)
Other working capital changes	1,557	10,962
Cash provided by continuing operations	115,044	87,423
Cash provided (used) by discontinued operations	(20,929)	1,821
Cash provided by operating activities	94,115	89,244
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures -		
Oil and gas properties	(72,797)	(58,973)
Gathering systems and other	(3,024)	(1,929)
Proceeds from sale of oil and gas properties	41,483	22,755
Proceeds from sale of company, net of cash sold	116,107	
Other	(2,717)	1,849
Cash provided (used) by investing activities - continuing operations	79,052	(36,298)
Cash provided (used) by investing activities - discontinued operations	10,309	(1,261)
Cash provided (used) by investing activities	89,361	(37,559)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	581	514
Purchase of treasury stock	(1,295)	

Issuance of 8 1/4% Notes		350,000
Redemption of 9% Senior Subordinated Notes due 2005	(50,750)	(103,000)
Advances on revolving credit facility and other borrowings	115,400	153,433
Payments on revolving credit facility and other borrowings	(147,436)	(409,492)
Dividends paid	(5,089)	(6,949)
Other		(9,875)
Cash used by financing activities	(88,589)	(25,369)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	2,670	(8,689)
NET INCREASE IN CASH AND CASH EQUIVALENTS	97,557	17,627
CASH AND CASH EQUIVALENTS, beginning of period	9,259	6,359
CASH AND CASH EQUIVALENTS, end of period	$ 106,816	$ 23,986

See notes to unaudited consolidated financial statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2003 and 2002

1. GENERAL

The accompanying financial statements are unaudited. The consolidated financial statements include the accounts of Vintage Petroleum, Inc. and its wholly- and majority-owned subsidiaries and its proportionately consolidated general partner and limited partner interests in various joint ventures (collectively, the Company). Management believes that all material adjustments (consisting of only normal recurring adjustments) necessary for a fair presentation have been made. All significant intercompany accounts and transactions have been eliminated in consolidation. Certain 2002 amounts have been reclassified to conform with the 2003 presentation, including reclassifications required for presentation of the discontinued operations discussed in Note 9. These reclassifications had no effect on the Company s net income (loss) or stockholders equity.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. These financial statements and notes should be read in conjunction with the 2002 audited financial statements and related notes included in the Company s 2002 Annual Report on Form 10-K, Item 8. Financial Statements and Supplementary Data.

2. SIGNIFICANT ACCOUNTING POLICIES

Oil and Gas Properties

Under the successful efforts method of accounting, the Company capitalizes all costs related to property acquisitions and successful exploratory wells, all development costs and the costs of support equipment and facilities. Certain costs of exploratory wells are capitalized pending determination that proved reserves have been found. Such determination is dependent upon the results of planned additional wells and the cost of required capital expenditures to produce the reserves found. All costs related to unsuccessful exploratory wells are expensed when such wells are determined to be non-productive; other exploration costs, including geological and geophysical costs, are expensed as incurred. The Company recognizes gains or losses on the sale of properties on a field basis.

Unproved leasehold costs are capitalized and reviewed periodically for impairment. Individual unproved properties whose acquisition costs are significant are assessed on a property-by-property basis, considering factors such as future drilling and exploration plans and lease terms. For unproved properties whose acquisition costs are not individually significant, the amount of those properties impairment is determined by amortizing the properties in groups on the basis of the Company s experience in similar situations and other information such as the primary lease terms, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past. Costs related to impaired prospects are charged to exploration expense. Further impairment expense could result if oil and gas prices decline in the future or if downward reserve revisions are recorded on nearby properties, as it may not be economic to develop some of these unproved properties.

As of June 30, 2003, the Company had total unproved oil and gas property costs of approximately $71.2 million, consisting of undeveloped leasehold costs of $52.4 million, including $39.2 million in Canada, and unproved exploratory drilling costs of $18.8 million. Approximately $21.8 million of the total unproved costs are associated with the Company s drilling program in Yemen. In the second quarter of 2003, the Company recorded additional exploration expense of $23.7 million ($13.9 million net of tax) to fully impair its undeveloped leaseholds in the Northwest Territories. Future exploration expense and earnings may be impacted to the extent that the Company s future exploration activities are unsuccessful in discovering commercial oil and gas reserves in sufficient quantities to recover its costs.

Costs of development dry holes and proved leaseholds are amortized on the unit-of-production method using proved reserves on a field basis. The depreciation of capitalized production equipment, drilling costs and asset retirement obligations is based on the unit-of-production method using proved developed reserves on a field basis.

In August 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). The Company was required to adopt this new standard beginning January 1, 2003. Through December 31, 2002, the Company accrued an estimate of future abandonment costs of wells and related facilities through its depreciation calculation and included the cumulative accrual in accumulated depreciation in accordance with the provisions of Statement of Financial Accounting Standards No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, and industry practice. At December 31, 2002, approximately $54.6 million of accrued future abandonment costs were included in accumulated depreciation. The new standard requires that the Company record the discounted fair value of the retirement obligation as a liability at the time a well is drilled or acquired. The asset retirement obligations consist primarily of costs associated with the plugging and abandonment of oil and gas wells, site reclamation and facilities dismantlement. However, future abandonment liabilities were also recorded for other assets such as pipelines, processing plants and compressors. A corresponding amount is capitalized as part of the related property s carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset. The liability accretes over time with a charge to accretion expense. At January 1, 2003, and at June 30, 2003, there were no assets legally restricted for purposes of settling asset retirement obligations.

The Company adopted the new standard effective January 1, 2003, and recorded an increase in property, plant and equipment of approximately $50.3 million, a net decrease in accumulated depreciation, depletion and amortization of approximately $43.9 million, an increase in current asset retirement liabilities of approximately $4.5 million, an increase in long-term asset retirement liabilities of approximately $78.5 million, an increase in deferred tax liabilities of approximately $4.1 million and a non-cash gain as a result of the cumulative effect of change in accounting principle, net of tax, of approximately $7.1 million.

Subsequent to the implementation of SFAS 143, the Company recorded the following activity related to the liability (in thousands):

Initial liability for asset retirement obligations as of January 1, 2003	$ 83,040
New obligations for wells drilled during the six months ended June 30, 2003	1,138
Obligations fulfilled during the six months ended June 30, 2003	(754)
Reversal of liability for dispositions of assets	(689)
Accretion expense	3,579
Changes in foreign currency exchange rates	1,386
Liability for asset retirement obligations as of June 30, 2003	$ 87,700

Of the liability for asset retirement obligations balance at June 30, 2003, approximately $4.5 million is classified as current and included in Other payables and accrued liabilities in the accompanying balance sheet.

Had the provisions of SFAS 143 been applied in 2002, the liability for asset retirement obligations would have been $78.1 million at January 1, 2002, and $82.2 at June 30, 2002, and the Company s net income (loss) and earnings per share would have been as follows (in thousands, except per share amounts):

	Three Months Ended June 30, 2002		**Six Months Ended June 30, 2002**	
	As Reported	**Pro Forma**	**As Reported**	**Pro Forma**
Net income (loss)	$ 22,429	$ 20,286	$ (43,738)	$ (47,974)
Income (loss) per share:				
Basic	$ 0.36	$ 0.32	$ (0.69)	$ (0.76)
Diluted	$ 0.35	$ 0.32	$ (0.68)	$ (0.75)

The Company reviews its proved oil and gas properties for impairment on a field basis. For each field, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of those properties may not be recoverable from estimated future net revenues. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and risk-adjusted probable and possible oil and gas reserves over the economic life of the reserves, based on the Company s expectations of future oil and gas prices and costs, consistent with price and cost assumptions used for acquisition evaluations. The Company recorded an impairment provision of $12.6 million related to its Canadian proved oil and gas properties in the second quarter of 2003. The Company recorded no impairment provisions related to its proved oil and gas properties during the first quarter of 2003 or the first six months of 2002.

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In estimating the future net revenues at June 30, 2003, to be used for impairment testing, the Company assumed that current oil prices would return to more historical levels over a short period of time and that current gas prices would remain at the levels experienced in recent years. The Company assumed that operating costs would escalate annually beginning at current levels. Due to the volatility of oil and gas prices, it is possible that the Company s assumptions regarding oil and gas prices may change in the future and may result in future impairment provisions.

On January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). SFAS 144 creates accounting and reporting standards to establish a single accounting model, based on the framework established in Statement of Financial Accounting Standards No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, for long-lived assets to be disposed of by sale. The adoption of SFAS 144 did not have a material impact on the Company s financial position or results of operations. See further discussion of discontinued operations in Note 9.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis Exploration Ltd. (Genesis) in May 2001. On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, *Business Combinations* (SFAS 141), and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (SFAS 142). SFAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS 142, goodwill is no longer subject to amortization. Rather, goodwill will be subject to at least an annual assessment for impairment by applying a fair-value based test. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer s intent to do so.

The Company s acquisition of Genesis was accounted for using the purchase method of accounting. The Company adopted SFAS 141 and SFAS 142 effective January 1, 2002, resulting in the elimination of goodwill amortization from statements of operations in future periods. Upon adoption, the Company recorded an impairment charge of $60.5 million related to the goodwill of its Canadian operations as a cumulative effect of a change in accounting principle in its statement of operations (see Note 5). The Company will assess the Canadian operation s goodwill as of December 31 each year and will perform interim tests for goodwill impairment should an event occur or circumstances change that would, more likely than not, indicate a possible goodwill impairment. On December 31, 2002, the Company recorded an additional impairment charge of $76.4 million as an operating expense resulting from its annual assessment. No impairment charges related to goodwill were recorded in the first half of 2003.

Hedging

The Company periodically uses hedges to reduce the impact of oil and natural gas price fluctuations. The Company accounts for its hedging activities under the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended, SFAS 133). SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of operations. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

For derivative instruments that qualify as cash flow hedges, the effective portion of the gain or loss on a derivative instrument is reported as a component of other comprehensive income and reclassified into sales revenue in the same period or periods during which the hedged forecasted transaction affects earnings. The effective portion is determined by comparing the cumulative change in fair value of the derivative to the cumulative change in the present value of the expected cash flows of the item being hedged. To the extent the cumulative change in the derivative exceeds the cumulative change in the present value of expected cash flows, the excess, if any, is recognized currently in earnings. If the cumulative change in present value of the expected cash flows exceeds the change in fair value of the derivative, the difference is ignored. Changes in the fair value of derivative financial instruments that do not qualify for accounting treatment as hedges, if any, are recognized currently as Other income. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flows.

Statements of Cash Flows

During the six months ended June 30, 2003 and 2002, the Company made cash payments for interest totaling $36.7 million and $35.2 million, respectively. Cash payments for U.S. income taxes of $29.9 million and $6.2 million were made during the first six months of 2003 and 2002, respectively. The Company made cash payments for foreign income taxes of $25.8 million and $4.7 million, primarily in Argentina, during the first six months of 2003 and 2002, respectively.

Earnings Per Share

Basic income (loss) per share was computed by dividing net income (loss) by the weighted average number of shares outstanding during the period. Diluted income per common share for all periods presented were computed assuming the exercise of all dilutive options, as determined by applying the treasury stock method. For the three months ended June 30, 2003, the assumed exercise for all options would have been anti-dilutive because the Company had a net loss for the period. Therefore, the amounts reported for basic and diluted loss per share were the same. Had the Company been in a net income position for this period, the Company s diluted weighted average outstanding common shares would have been 65,427,000.

For the three month period ended June 30, 2003 and 2002, the Company had outstanding stock options for 4,348,000 and 3,125,000 additional shares of the Company s common stock, respectively, with average exercise prices of $7.79 and $19.18, respectively, which were anti-dilutive. For the six month period ended June 30, 2003 and 2002, the Company had outstanding stock options for 1,076,000 and 3,152,000 additional shares of the Company s common stock, respectively, with an average exercise price of $14.87 and $19.12, respectively, which were anti-dilutive. These shares will dilute basic earnings per share in the future, if exercised, and may impact diluted earnings per share in the future, depending on the market price of the Company s common stock.

General and Administrative Expense

The Company receives fees for the operation of jointly-owned oil and gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $2.1 million and $2.5 million for the first six months of 2003 and 2002, respectively, and approximately $0.9 and $1.2 million for the second quarters of 2003 and 2002, respectively.

Lease Operating Expense

On February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002, which is reflected in lease operating expenses. The tax is limited by law to a term of no more than five years. The 20 percent tax is applied on the sales value after the tax, thus the net effect is 16.7 percent.

Included in lease operating expenses are the following items (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Argentine oil export taxes	$ 8,183	$ 10,093	$ 18,405	$ 10,614
Transportation and storage expenses	2,067	2,042	4,038	4,422
Gross production taxes	2,675	2,757	5,705	4,938

The Company had $13.1 million and $12.9 million of accrued lease operating expenses at June 30, 2003, and December 31, 2002, respectively, included in Other payables and accrued liabilities in the accompanying balance sheets.

Foreign Currency

Foreign currency transactions and financial statements are translated in accordance with Statement of Financial Accounting Standards No. 52, *Foreign Currency Translation*. All of the Company s subsidiaries use the U.S. dollar as their functional currency except for the Company s Canadian operating subsidiary, which uses the Canadian dollar. Adjustments arising from translation of the Canadian operating subsidiary s financial statements are reflected in other comprehensive income (loss). Transaction gains and losses that arise from exchange rate fluctuations applicable to transactions denominated in a currency other than the Company s or its subsidiaries functional currency are included in the results of operations as incurred.

International investments represent, and are expected to continue to represent, a significant portion of the Company s business. For the first six months of 2003, the Company s operations in Argentina represented approximately 34 percent of the Company s total revenues and as of June 30, 2003, represented approximately 28 percent of the Company s total assets.

Beginning in 1991, the Argentine peso (peso) was tied to the U.S. dollar at a rate of one peso to one U.S. dollar. As a result of economic instability and substantial withdrawals from the banking system, in early December 2001, the Argentine government instituted restrictions that prohibit foreign money transfers without Central Bank approval and limit cash withdrawals from bank accounts to personal transactions in small amounts with certain limited exceptions. While the legal exchange rate remained at one peso to one U.S. dollar, financial institutions were allowed to conduct only limited activity due to these controls, and currency exchange activity was effectively halted except for personal transactions in small amounts. These actions by the government in effect caused a devaluation of the peso in December 2001.

On January 6, 2002, the Argentine government abolished the one peso to one U.S. dollar legal exchange rate. On January 9, 2002, Decree 71 created a dual exchange market whereby foreign trade transactions were conducted at an official exchange rate of 1.4 pesos to one U.S. dollar and other transactions were conducted in a free floating exchange market. On February 8, 2002, Decree 260 unified the dual exchange markets and allowed the peso to float freely with the U.S. dollar. The exchange rate at June 30, 2003, was 2.82 pesos to one U.S. dollar compared to 3.38 pesos to one U.S. dollar at December 31, 2002.

On February 3, 2002, Decree 214 required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Pursuant to an emergency law passed on January 10, 2002, U.S. dollar obligations between private parties due after January 6, 2002, were to be liquidated in pesos at a negotiated rate of exchange which reflects a sharing of the impact of the devaluation. The Company s settlements in pesos of the existing U.S. dollar-denominated agreements were completed in the first half of 2002, thus future periods will not be impacted by this mandate. This government-mandated equitable sharing of the impact of the devaluation resulted in a reduction in oil revenues from domestic sales in Argentina for the first six months of 2002 of approximately $8 million, or $1.37 per Argentine barrel produced, $0.76 per total continuing operations barrel produced or $0.73 per total Company barrel produced. The reduction of the Company s Argentine lease operating costs, which were also reduced as a result of this mandate and the positive impact of devaluation on the Company s peso-denominated costs, essentially offset the negative impact on Argentine oil revenues for the first six months of 2002. A $0.9 million gain resulting from the involuntary conversion was recorded in January 2002. Absent the January 10, 2002, emergency law, the devaluation of the peso would have had no effect on the U.S. dollar-denominated payables and receivables at December 31, 2001.

The Company has evaluated the effect of the economic and political events in Argentina. Despite these changes, the Company believes that the facts and circumstances indicate that the U.S. dollar remains the functional currency of its Argentine operations.

Stock-based Compensation

The Company has two fixed stock-based compensation plans which reserve shares of common stock for issuance to key employees and directors. The Company accounts for these plans under Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (SFAS 123). Accordingly, no compensation cost for stock options granted has been recognized, as all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the grant date. Compensation expense for restricted stock awards is recorded over the vesting period of the awards.

On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure* (SFAS 148). SFAS 148 amends SFAS 123 to provide alternative methods of transition to SFAS 123 s fair value method of accounting for stock-based employee compensation. The Company is considering the adoption of SFAS 123 s fair value method of accounting for stock-based employee compensation in 2003, but has not yet made a final determination.

Had compensation cost for these plans been determined consistent with the provisions of SFAS 123, the Company s stock-based compensation expense, net income (loss) and income (loss) per share would have been adjusted to the following pro forma amounts (in thousands, except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Stock-based compensation expense - as reported	$ 1,482	$ 397	$ 2,434	$ 413
Stock-based compensation expense - pro forma	1,452	1,410	3,057	2,790
Net income (loss) - as reported	(8,687)	22,429	31,994	(43,738)
Net income (loss) - pro forma	(8,670)	21,698	31,562	(45,449)
Income (loss) per share - as reported:				
Basic	(0.14)	0.36	0.50	(0.69)
Diluted	(0.14)	0.35	0.49	(0.68)
Income (loss) per share - pro forma:				
Basic	(0.14)	0.34	0.49	(0.72)
Diluted	(0.14)	0.34	0.48	(0.71)

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average assumptions used for options granted in 2003 include a dividend yield of 1.6 percent, expected volatility of approximately 43.9 percent, a risk-free interest rate of approximately 2.6 percent and expected lives of 4.5 years. The weighted average assumptions used for options granted in 2002 include a dividend yield of 1.4 percent, expected volatility of approximately 50.3 percent, a risk-free interest rate of approximately 4.4 percent and expected lives of 4.5 years.

Comprehensive Income (Loss)

Comprehensive income (loss) consists of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Net income (loss)	$ (8,687)	$ 22,429	$ 31,994	$ (43,738)
Foreign currency translation adjustments	42,314	31,932	75,698	31,432
Changes in value of derivatives, net of tax	1,206	5,693	(2,809)	(3,246)
Comprehensive income (loss)	$ 34,833	$ 60,054	$ 104,883	$ (15,552)

The foreign currency translation adjustments shown above relate entirely to the translation of the financial statements of the Company s Canadian operating subsidiary from its functional currency, the Canadian dollar, to the Company s reporting currency, the U.S. dollar.

The changes in the value of derivatives, net of tax, consist of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Unrealized gain (loss) during the period	$ (1,605)	$ 12,329	$ (14,704)	$ (370)
Reclassification adjustment for (gains) losses included in net income (loss)	4,622	(2,804)	10,917	(4,700)
	3,017	9,525	(3,787)	(5,070)
Income tax (provision) benefit	(1,811)	(3,832)	978	1,824
Changes in value of derivatives, net of tax	$ 1,206	$ 5,693	$ (2,809)	$ (3,246)

The accumulated balance for each item in accumulated other comprehensive income (loss) is as follows (in thousands):

	June 30,	
	2003	2002
Foreign currency translation adjustments	$ 56,041	$ 6,810

Changes in value of derivatives, net of tax	(11,725)	(256)
	$ 44,316	$ 6,554

Recent Pronouncements

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51* (FIN 46). FIN 46 requires the consolidation of entities in which an enterprise absorbs a majority of the entity s expected losses, receives a majority of the entity s expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Currently, entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority of voting interest in the entity. The Company expects FIN 46 to have no impact on its financial position or results of operations.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS 149). SFAS 149 is intended to result in more consistent reporting of contracts as either freestanding derivative instruments subject to SFAS 133 in its entirety, or as hybrid instruments with debt host contracts and embedded derivative features. SFAS 149 is effective for contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003. The Company does not expect the adoption of SFAS 149 to have a material impact on its financial position or results of operations.

On May 15, 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS 150). SFAS 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. SFAS 150 must be applied immediately to instruments entered into or modified after May 31, 2003, and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. Early adoption of SFAS 150 is not permitted. The Company does not expect the adoption of SFAS 150 to have a material impact on its financial position or results of operations.

3. LONG-TERM DEBT

Long-term debt at June 30, 2003, and December 31, 2002, consisted of the following (in thousands):

	June 30, 2003	December 31, 2002
Revolving credit facility	$ 3,100	$ 33,800
8 1/4% Senior Notes due 2012	350,000	350,000
Senior Subordinated Notes:		
9% Notes due 2005, less unamortized discount		49,958
8 5/8% Notes due 2009, less unamortized discount	99,495	99,484
9 3/4% Notes due 2009	150,000	150,000
7 7/8% Notes due 2011, less unamortized discount	199,940	199,938
	$ 802,535	$ 883,180

During the first quarter of 2003, the Company advanced funds under the revolving credit facility to redeem the remainder of the 9% Notes due 2005. As a result, the Company was required to expense certain associated deferred financing costs and discounts. This $0.7 million non-cash charge and a $0.7 million cash charge for the call premium on the redemption of the remaining 9% Notes resulted in a one-time charge of approximately $1.4 million ($0.9 million net of tax). Subsequently, a portion of the proceeds from the January 2003 sale of the Company s operations in Ecuador was used to repay the entire outstanding balance under the revolving credit facility. At June 30, 2003, the unused availability under the revolving credit facility was $287.2 million, considering outstanding letters of credit of $9.7 million.

The revolving credit facility matures in 2005. All of the Company s other outstanding debt matures in 2009 or later. The Company had $10.9 million and $11.7 million of accrued interest payable related to its long-term debt at June 30, 2003, and December 31, 2002, respectively, included in Other payables and accrued liabilities in the accompanying balance sheets.

4. CAPITAL STOCK

On February 20, 2003, pursuant to the terms of an offer to exchange, the Company accepted for exchange options to purchase 2,118,000 shares of its common stock, representing approximately 95.1% of the 2,227,500 options that were eligible to be tendered in the offer. The options exchanged had exercise prices ranging from $19.28 to $21.81 per share. In accordance with the terms of the offer to exchange, the Company granted restricted stock and restricted stock rights, both of which vest over a three-year period, representing an aggregate of 562,840 shares of its common stock in exchange for the tendered options. Restricted stock award compensation expense of approximately $5.5 million (based on the stock price on the date of grant) will be amortized over the vesting periods.

In addition to the offer to exchange discussed above, in the first half of 2003 the Company has granted restricted stock and restricted stock rights representing an aggregate of 332,700 shares of its common stock, net of forfeitures. The restricted stock and restricted stock rights generally vest over a three-year period. The related restricted stock compensation expense, net of forfeitures, of $3.4 million (based on the stock price on the date of grant) is being amortized over the vesting periods.

Subsequent to June 30, 2003, the Company granted 200,000 shares of restricted stock to certain senior executives of the Company. These restricted shares will vest on the later of one year from the date of grant or when the Company s common stock price has closed at $15.00 per share or higher for 45 consecutive trading days. These restricted stock awards will be forfeited in three years if not vested by that date. The Company will record compensation expense when the stock price criterion has been met.

The Company declared cash dividends of $0.085 and $0.075 per share for the six months ended June 30, 2003 and 2002, respectively, and $0.045 and $0.04 per share for the three months ended June 30, 2003 and 2002, respectively.

5. GOODWILL

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis. All of the Company s goodwill is related to the Company s Canadian operations, which is consistent with the Canadian segment identified in Note 10. Effective January 1, 2002, the Company adopted the provisions of SFAS 142. SFAS 142 changed the accounting for goodwill from an amortization method to an impairment-only method.

Under the new rule, the Company had a six-month transition period from the effective date of the adoption to perform an initial assessment of whether there was an indication that the carrying value of goodwill was impaired. This assessment was made by comparing the fair value of the Canadian operations, as determined in accordance with SFAS 142, to its book value. If the fair value was less than the book value, an impairment was indicated and the Company would be required to perform a second test no later than December 31, 2002, to measure the amount of the impairment. Any initial impairment was to be taken as a cumulative effect of change in accounting principle retroactive to January 1, 2002. In future years, this assessment must be conducted at least annually and any such impairment must be recorded as a charge to operating expense.

The Company completed its initial assessment in the second quarter of 2002 and recorded a non-cash charge of $60.5 million. Decreases in oil and gas price expectations from the May 2, 2001, acquisition of Genesis to January 1, 2002, and certain downward revisions recorded to the Company s Canadian oil and gas reserves at December 31, 2001, were the primary factors that led to the goodwill impairment. The charge was recorded as a cumulative effect of change in accounting principle retroactive to January 1, 2002, in accordance with the provisions of SFAS 142. The Company performed another assessment of goodwill impairment as of December 31, 2002, and recorded an additional non-cash charge of $76.4 million as an operating expense. Certain downward revisions recorded to the Company s Canadian oil and gas reserves in the fourth quarter of 2002 were the primary factor which led to the additional impairment.

The Company engaged an independent appraisal firm to determine the fair value of the Canadian operations as of January 1, 2002, and December 31, 2002. These fair value determinations were made principally on the basis of present value of future after tax cash flows, although other valuation methods were considered. The book value of the Canadian operations exceeded the fair value determined by the independent appraisal firm, indicating a possible impairment of goodwill. The Company then calculated the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the Canadian operations from the fair value of the Canadian operations determined in step one of the assessment. The carrying value of the goodwill exceeded this calculated implied fair value of the goodwill at January 1, 2002, and at December 31, 2002, resulting in the impairment charges.

The Company has no intangible assets other than the goodwill of its Canadian operations. This goodwill had a net book value of $24.7 million as of June 30, 2003. The changes in the carrying amount of goodwill for the six months ended June 30, 2003 and 2002, are as follows (in thousands):

	Six Months Ended June 30,	
	2003	**2002**
Balance, beginning of period	$ 21,099	$ 156,990
Impairment		(60,547)
Changes in foreign currency exchange rates	3,603	8,012
Balance, end of period	$ 24,702	$ 104,455

As noted above, SFAS 142 required that the cumulative effect of change in accounting principle be recorded retroactive to January 1, 2002. The following table reflects the impact of this accounting change on selected financial data for the three months ended March 31, 2002 (in thousands, except per share data):

	As Reported	As Restated
Loss before cumulative effect of change in accounting principle	$ (5,620)	$ (5,620)
Cumulative effect of change in accounting principle		(60,547)
Net loss	$ (5,620)	$ (66,167)
Basic Loss Per Share:		
Loss before cumulative effect of change in accounting principle	$ (0.09)	$ (0.09)
Cumulative effect of change in accounting principle		(0.96)
Net loss	$ (0.09)	$ (1.05)
Diluted Loss Per Share:		
Loss before cumulative effect of change in accounting principle	$ (0.09)	$ (0.09)
Cumulative effect of change in accounting principle		(0.96)
Net loss	$ (0.09)	$ (1.05)

6. COMMITMENTS AND CONTINGENCIES

The Company had approximately $9.7 million in letters of credit outstanding at June 30, 2003. These letters of credit relate primarily to various obligations for exploration activities in South America and bonding requirements of various state regulatory agencies in the U.S. for oil and gas operations. The Company s availability under its revolving credit facility is reduced by the outstanding letters of credit.

The Company has entered into certain firm gas transportation and compression agreements in Bolivia whereby the Company has committed to transport and compress certain volumes of gas at established government-regulated fees. While these fees are not fixed, they are government-regulated and therefore, the Company believes the risk of significant fluctuations is minimal. The Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to utilize all of the contracted transportation and compression capacity under these arrangements. Based on the current fee level, these commitments total approximately $1.3 million for the remainder of 2003, $1.4 million in 2004 and $0.3 million in each of the years 2005 through 2009.

The Company has future minimum long-term electric power purchase commitments in Argentina of $0.9 million for the remainder of 2003, $3.6 million in 2004, $3.6 million in 2005 and $7.6 million in 2006.

The Company was committed to perform a certain number of work units in the Chaco concession in Bolivia. The Company fulfilled this commitment by performing exploration work in the first half of 2003 and the $6.5 million associated letter of credit outstanding at June 30, 2003, has now been released.

7. PRICE RISK MANAGEMENT

The Company periodically uses hedges to reduce the impact of oil and natural gas price fluctuations on its operating results and cash flows. The Company participated in oil hedges covering approximately 2.3 million barrels and gas hedges covering approximately 10.0 million MMBtu (millions of British thermal units) in the first six months of 2003. The impact of the oil hedges decreased its U.S. average oil price by $3.06 to $25.49 per barrel, its Canada average oil price by $0.04 to $28.56 per barrel, its average oil price from continuing operations by $1.09 to $26.58 per barrel and its overall average oil price by $1.07 to $26.58 per barrel. The impact of the gas hedges decreased its U.S. average gas price by $0.80 to $4.43 per Mcf (thousand cubic feet), decreased its Canada average gas price by $0.62 to $4.46 per Mcf and decreased its overall average gas price by $0.53 to $3.58 per Mcf.

At June 30, 2003, the Company was a party to oil price swap agreements for various periods of the remainder of 2003 covering approximately 1.8 million barrels at a weighted average NYMEX reference price of $24.98 per barrel and gas price swap agreements for various periods of the remainder of 2003 covering approximately 10.1 million MMBtu. The U.S. portion of the gas swap agreements, approximately 5.5 million MMBtu, is at a weighted average NYMEX reference price of $3.96 per MMBtu. The Canadian portion of the gas swap agreements, approximately 4.6 million MMBtu, is at a weighted average NYMEX reference price of 6.52 Canadian dollars per MMBtu. Additionally, the Company has entered into basis swap agreements for the approximately 4.2 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. At June 30, 2003, the Company had a derivative financial instrument payable of $19.7 million related to cash flow hedges in place for anticipated 2003 production. Subsequent to June 30, 2003, the Company entered into additional oil price swap agreements for various periods of the remainder of 2003 for 611,000 barrels at a weighted average NYMEX reference price of $30.41 per barrel and for the first quarter of 2004 for 182,000 barrels at a weighted average NYMEX reference price of $28.97 per barrel. The Company did not discontinue any hedges because of the probability that the original forecasted transaction would not occur. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

8. INCOME TAXES

A reconciliation of the U.S. federal statutory income tax rate to the effective rate for continuing operations is as follows:

	Six Months Ended June 30,	
	2003	**2002**
U.S. federal statutory income tax rate	35.0%	35.0%
U.S. state income tax (net of federal tax benefit)	1.6	0.6
Foreign operations	13.2	(30.1)
U.S. permanent differences	0.9	1.0
	50.7%	6.5%

The impact of foreign operations for the first half of 2002 is primarily the result of the Company s impairment of its goodwill related to its Canadian operations which is not deductible for income tax purposes. As the Company was in a net loss position for the period, this non-deductible expense had the effect of reducing the Company s net tax benefit and its overall effective tax rate.

The impact of foreign operations for the first half of 2003 is primarily the continuing effect of the peso devaluation on the Company s Argentine tax balance sheet due to the inability, to date, to utilize inflation accounting for fixed assets and the unfavorable Argentine tax impact on U.S. dollar-denominated liabilities due to the strengthening of the peso in the first half of 2003.

9. DISCONTINUED OPERATIONS

On July 30, 2002, the Company completed the sale of its operations in Trinidad. The Company received $40 million in cash and recorded a gain of approximately $31.9 million ($14.9 million after income taxes). On January 31, 2003, the Company completed the sale of its operations in Ecuador. The Company received $137.4 million in cash and recorded a gain of approximately $47.3 million ($9.5 million after income taxes), subject to post-closing adjustments.

In accordance with the rules established by SFAS 144, the Company s operations in Trinidad and Ecuador, along with the gain on the sale of the operations in Ecuador, are accounted for as discontinued operations in the accompanying consolidated financial statements.

Following is summarized financial information for the Company s Trinidad operations (in thousands):

	Three Months Ended June 30, 2002	Six Months Ended June 30, 2002
Loss from discontinued operations	$ (598)	$ (709)
Deferred tax benefit	(214)	(253)
Loss from discontinued operations, net of tax	$ (384)	$ (456)

Following is summarized financial information for the Company s operations in Ecuador (in thousands):

	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
Income from discontinued operations	$ 1,812	$ 3,652
Deferred tax expense	459	914
Net operating income from discontinued operations	1,353	2,738
Gain on sale of operations in Ecuador, net of $37,767 income tax expense	9,491	
Income from discontinued operations, net of tax	$ 10,844	$ 2,738

	Three Months Ended June 30, 2002
Income from discontinued operations	$ 2,654
Deferred tax expense	663
Income from discontinued operations, net of tax	$ 1,991

	December 31, 2002
Current assets	$ 19,365
Property, plant and equipment, net	58,968
Other assets, net	2,676
Deferred income tax asset	5,165
Assets of discontinued operations	$ 86,174
Current liabilities of discontinued operations	$ 10,769

The income tax expense related to the gain on the sale of operations in Ecuador includes $19.4 million of taxes on previously unremitted foreign earnings. As it is the Company s intention, generally, to reinvest foreign earnings permanently, no U.S. income taxes were previously recorded on these earnings. In accordance with SFAS 144, the assets of the Company s operations in Ecuador were reclassified as Assets of discontinued operations and the liabilities were reclassified as Liabilities of discontinued operations in the accompanying consolidated balance sheet as of December 31, 2002.

10. SEGMENT INFORMATION

The Company applies Statement of Financial Accounting Standards No. 131, *Disclosures About Segments of an Enterprise and Related Information*. The Company s reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production segment are derived from the production and sale of natural gas and crude oil. Revenues for the gathering/plant segment arise from the processing, transportation and sale of natural gas and crude oil. The gas marketing segment generates revenue by earning fees through the marketing of Company-produced gas volumes and the purchase and resale of third party-produced gas volumes. The Company evaluates the performance of its operating segments based on segment operating income.

Operations in the gathering/plant and gas marketing segments are in the United States. The Company operates in the oil and gas exploration and production industry in the United States, Canada, South America, Yemen and Italy. The financial information related to the Company s discontinued operations in Trinidad and Ecuador has been excluded in all periods presented (see Note 9), except for total assets at the end of June 30, 2002. Summarized financial information for the Company s reportable segments for the six month and three month periods ended June 30, 2003 and 2002, is shown in the following tables (in thousands):

	Exploration and Production				
	U.S.	Canada	Argentina	Bolivia	Other Foreign
Six Months Ended June 30, 2003					
Revenues from external customers	$ 133,160	$ 65,702	$ 138,828	$ 7,143	$
Intersegment revenues					
Depreciation, depletion and amortization expense	19,860	27,813	20,880	1,430	
Segment operating income (loss)	61,008	(30,500)	73,533	2,302	(2,700)
Total assets	452,091	601,651	529,230	121,930	22,860
Capital investments	32,899	14,993	19,621	1,419	8,743
Long-lived assets	419,547	577,425	474,802	92,859	22,028

	Gathering/ Plant	Gas Marketing	Corporate	Total
Six Months Ended June 30, 2003				
Revenues from external customers	$ 3,510	$ 59,661	$ (5,195)	$ 402,809
Intersegment revenues		626		626
Depreciation, depletion and amortization expense	346		1,748	72,077
Segment operating income (loss)	(1,227)	1,239	(6,943)	96,712
Total assets	12,405	13,641	136,623	1,890,431
Capital investments	1,451		1,169	80,295
Long-lived assets	9,767		5,700	1,602,128

	Exploration and Production				
	U.S.	Canada	Argentina	Bolivia	Other Foreign
Six Months Ended June 30, 2002					
Revenues from external customers	$ 122,282	$ 55,291	$ 105,132	$ 6,176	$
Intersegment revenues					
Depreciation, depletion and amortization expense	28,662	38,000	24,657	1,944	
Segment operating income (loss)	43,794	(16,255)	49,411	2,116	(161)
Total assets	454,826	782,381	508,931	116,361	21,455
Capital investments	14,229	34,282	12,466	1,112	743
Long-lived assets	417,859	760,065	464,057	92,685	21,347

	Gathering/ Plant	Gas Marketing	Corporate	Total

Six Months Ended June 30, 2002				
Revenues from external customers	$ 2,853	$ 29,733	$ 5,294	$ 326,761
Intersegment revenues		454		454
Depreciation, depletion and amortization expense	589		1,465	95,317
Segment operating income (loss)	(1,018)	988	3,829	82,704
Total assets	8,907	9,428	145,484	2,047,773
Capital investments			872	63,704
Long-lived assets	6,375		7,089	1,769,477

	Exploration and Production				
	U.S.	Canada	Argentina	Bolivia	Other Foreign
Three Months Ended June 30, 2003					
Revenues from external customers	$ 63,434	$ 27,256	$ 65,101	$ 4,035	$
Intersegment revenues					
Depreciation, depletion and amortization expense	9,782	12,479	10,582	781	
Segment operating income (loss)	29,798	(38,042)	33,084	1,041	(851)
Total assets	452,091	601,651	529,230	121,930	22,860
Capital investments	12,637	3,497	12,559	1,162	3,398
Long-lived assets	419,547	577,425	474,802	92,859	22,028

	Gathering/ Plant	Gas Marketing	Corporate	Total
Three Months Ended June 30, 2003				
Revenues from external customers	$ 1,556	$ 26,741	$ (1,310)	$ 186,813
Intersegment revenues		298		298
Depreciation, depletion and amortization expense	464		695	34,783
Segment operating income (loss)	(703)	356	(2,005)	22,678
Total assets	12,405	13,641	136,623	1,890,431
Capital investments	659		1,092	35,004
Long-lived assets	9,767		5,700	1,602,128

	Exploration and Production				
	U.S.	Canada	Argentina	Bolivia	Other Foreign
Three Months Ended June 30, 2002					
Revenues from external customers	$ 77,150	$ 30,440	$ 60,319	$ 2,564	$
Intersegment revenues					
Depreciation, depletion and amortization expense	13,101	19,116	12,000	770	
Segment operating income (loss)	40,443	(5,175)	28,562	830	(81)
Total assets	454,826	782,381	508,931	116,361	21,455
Capital investments	6,993	14,931	4,505	1,013	155
Long-lived assets	417,859	760,065	464,057	92,685	21,347

	Gathering/ Plant	Gas Marketing	Corporate	Total
Three Months Ended June 30, 2002				
Revenues from external customers	$ 1,468	$ 17,405	$ 1,609	$ 190,955
Intersegment revenues		283		283
Depreciation, depletion and amortization expense	314		775	46,076
Segment operating income (loss)	(350)	463	835	65,527
Total assets	8,907	9,428	145,484	2,047,773

Capital investments		374	27,971
Long-lived assets	6,375	7,089	1,769,477

Intersegment sales are priced in accordance with terms of existing contracts and current market conditions. Capital investments include expensed exploratory costs. Long-lived assets include property, plant and equipment and goodwill. Corporate general and administrative costs and interest costs, including the loss on early extinguishment of debt, are not allocated to segments.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Results of Operations

The Company s results of operations have been significantly affected by its success in acquiring oil and gas properties and its ability to maintain or increase production through its exploitation and exploration activities. Significant dispositions of producing oil and gas properties during 2002 and 2003 affect the comparability of operating data for the periods presented in the tables below. Fluctuations in oil and gas prices and substantially curtailed capital expenditure levels in 2002 have also significantly affected the Company s results. Production from continuing operations for the first half of 2003 of 13.9 million BOE is consistent with the Company s expectations. The anticipated decline from 16.3 million BOE for the first half of 2002 was attributable to U.S. property divestitures in June 2002 and March 2003, natural production declines and the effects of substantially curtailed capital expenditures in 2002 which resulted in significantly lower production levels at the beginning of 2003. Capital expenditures in 2002 were limited to $129.7 million, or approximately 54 percent of cash flow provided by operating activities, as a result of the Company s decisions to use a portion of cash flow and proceeds from asset sales to execute its debt reduction program during 2002. The following table reflects the Company s oil and gas production and its average oil and gas sales prices for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Production:				
Oil (MBbls) -				
U.S.	1,613	1,829	3,169	3,575
Canada	297	452	671	980
Argentina (a)	2,538	2,842	5,064	5,835
Bolivia (b)	21	32	40	71
Continuing operations	4,469	5,155	8,944	10,461
Ecuador		282	114	546
Total	4,469	5,437	9,058	11,007
Gas (MMcf) -				
U.S.	5,960	6,527	11,977	12,480
Canada	4,486(c)	8,250	10,362	15,406
Argentina	2,561	2,466	4,591	3,967
Bolivia	1,635	1,319	3,053	3,345
Total	14,642(c)	18,562	29,983	35,198
MBOE from continuing operations	6,909	8,249	13,941	16,327
Total MBOE	6,909	8,531	14,055	16,873

(a) Production for Argentina for the three months ended June 30, 2003 and 2002, and for the six months ended June 30, 2003 and 2002, before the impact of changes in inventories was 2,526 MBbls, 2,772 MBbls, 5,055 MBbls and 5,618 MBbls, respectively.

(b) Production for Bolivia for the three months ended June 30, 2003 and 2002, and for the six months ended June 30, 2003 and 2002, before the impact of changes in inventories was 21 MBbls, 22 MBbls, 41 MBbls and 50 MBbls, respectively.

(c) Volumes for Canada and total gas production and total MBOE for the second quarter of 2003 were 5,271 MMcf, 15,427 MMcf and 7,040 MBOE respectively, before the impact of a change in estimated volumes (for periods prior to the second quarter of 2003) related primarily to Canadian sliding-scale royalty adjustments. As commodity prices increase the sliding-scale royalty burden increases, lowering reported net volumes. Previous estimates did not fully reflect the impact of the higher commodity prices realized.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Average Sales Price (including impact of hedges):				
Oil (per Bbl) -				
U.S.	$ 24.47	$ 21.80	$ 25.49	$20.05
Canada	25.64	22.60	28.56	19.96
Argentina	25.19	20.92	27.02	17.76(a)
Bolivia	23.29	21.87	22.90	19.81
Continuing operations	24.95	21.39	26.58	18.76(a)
Ecuador		20.88	26.87	18.24
Total	24.95	21.36	26.58	18.74(a)
Gas (per Mcf) -				
U.S.	$ 4.02	$ 3.01	$ 4.43	$ 2.64
Canada	4.31	2.43	4.46	2.32
Argentina	0.46	0.35	0.44	0.38
Bolivia	2.17	1.42	2.04	1.42
Total	3.28	2.29	3.58	2.13
Average Sales Price (excluding impact of hedges):				
Oil (per Bbl) -				
U.S.	$ 25.71	$ 22.85	$ 28.55	$20.31
Canada	25.41	22.60	28.60	19.96
Argentina	25.19	21.15	27.02	17.91(a)
Bolivia	23.29	21.87	22.90	19.81
Continuing operations	25.38	21.89	27.67	18.93(a)
Ecuador		20.88	26.87	18.24
Total	25.38	21.83	27.65	18.90(a)
Gas (per Mcf) -				
U.S.	$ 4.68	$ 3.19	$ 5.23	$ 2.73
Canada	4.76	2.55	5.08	2.38
Argentina	0.46	0.35	0.44	0.38
Bolivia	2.17	1.42	2.04	1.42
Total	3.69	2.40	4.11	2.19

(a) Reflects the impact of the one-time government-mandated forced settlement of domestic Argentine oil sales, which decreased the amounts for Argentina, total continuing operations and total average oil prices per Bbl for the six months ended June 30, 2002, by $1.37, $0.76 and $0.73, respectively.

Oil Prices

Average U.S. and Canadian oil prices received by the Company fluctuate generally with changes in the NYMEX reference price for oil. The Company s oil production in Argentina is sold at West Texas Intermediate spot prices as quoted on the Platt s Crude Oil Marketwire (approximately equal to the NYMEX reference price) less a specified differential. During the first six months of 2003, the Company experienced a 42 percent increase in its average oil price, including the impact of hedging activities (46 percent increase excluding hedging activities), compared to the same period in 2002. The Company s realized average oil price for the first six months of 2003 before hedges increased to 88 percent of the NYMEX reference price compared to 79 percent for the same period in 2002. This increase in realizations is primarily a result of the impact of the one-time government-mandated forced settlement of domestic Argentine oil sales in 2002 and the sale of the Company s heavy oil assets in June 2002. These heavy oil assets generally realized lower prices relative to NYMEX than the Company s other oil production.

As discussed in Note 2 to the Company s consolidated financial statements included elsewhere in this Form 10-Q, the Argentine government took actions which in effect caused the devaluation of the peso in early December 2001 and, in January 2002, enacted an emergency law that required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Subsequently, on February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax of 20 percent is applied on the sales value after the tax, thus the net effect is 16.7 percent and is included in lease operating expenses in the Company s statement of operations. The tax is limited by law to a term of no more than five years. For additional information, see Item 3. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk included elsewhere in this Form 10-Q. Domestic Argentine oil sales, while valued in U.S. dollars, are now being paid in pesos. Export oil sales continue to be valued and paid in U.S. dollars.

The Company currently exports approximately 70 percent of its Argentine oil production. The Company believes that export tax has continued to have the effect of decreasing all future Argentine oil revenues, not only export revenues, by the tax rate for the duration of the tax. The U.S. dollar equivalent value for domestic Argentine oil sales, now paid in pesos, has generally moved to parity with the U.S. dollar-denominated export values, net of the export tax. The adverse impact of this tax is partially offset by the net cost savings from the devaluation of the peso on peso-denominated costs and is further reduced by the Argentine income tax savings related to deducting the impact of the export tax. The export tax is not deducted in the calculation of royalty payments.

Beginning in 2003, at the Argentine government s request, crude oil producers and refiners agreed to limit amounts payable for domestic sales to a maximum $28.50 per barrel. The producers and refiners further agreed that the difference between the actual price and the maximum price would be payable once actual prices fall below the maximum, however, the refiners have no obligation to pay producers for sales values that exceed $36.00 per barrel. The debt payable under the agreement accrues interest at rates of seven to eight percent. The total debt will be collected by invoicing future deliveries at $28.50 per barrel after actual prices fall below the maximum price. This agreement expired on July 31, 2003. However, the Company believes that, in the near future, the agreement will be extended to September 30, 2003.

The Company sold approximately 660,000 net Bbls of its Argentine oil production under this agreement in the first six months of 2003. The Company has not recorded revenue for any amounts above the $28.50 per barrel maximum that have not yet been received. Repayments received from refiners will be recorded as revenues when received.

During the first six months of 2003 and 2002, the Company participated in oil hedges covering approximately 2.3 MMBbls and 2.2 MMBbls, respectively. The impacts of these oil hedges on the Company s average oil prices are reflected in the preceding tables.

Gas Prices

Average U.S. gas prices received by the Company fluctuate generally with changes in spot market prices, which may vary significantly by region. The Company s gas in Canada is generally sold at spot market prices as reflected by the AECO gas price index. Most of the Company s Bolivian gas production is sold at average prices tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. The Company s Argentine gas is sold under spot contracts of varying lengths, which, as a result of the emergency law enacted in January 2002, are now paid in pesos. This has initially resulted in a decrease in sales revenue value when converted to U.S. dollars due to the devaluation of the peso and current market conditions. This value may improve over time as domestic Argentine gas drilling declines and market conditions improve. The Company s total average gas price for the first six months of 2003, including the impact of hedging activities, was 68 percent higher (88 percent higher excluding hedging activities) than the same period of 2002.

The Company participated in gas hedges covering approximately 10.0 million MMBtu and 3.8 million MMBtu during the first six months of 2003 and 2002, respectively. The impacts of these gas hedges on the Company s average gas prices are reflected in the preceding tables.

Future Period Hedges

The Company has previously engaged in oil and gas hedging activities and intends to continue to consider various hedging arrangements to realize commodity prices which it considers favorable. The Company has entered into various oil price swap agreements for various periods of the remainder of 2003 covering approximately 2.4 million barrels at a weighted average NYMEX reference price of $26.35 per barrel and gas price swap agreements for various periods of the remainder of 2003 covering approximately 10.1 million MMBtu. The U.S. portion of the gas swap agreements, approximately 5.5 million MMBtu, is at an average NYMEX reference price of $3.96 per MMBtu. The Canadian portion of the gas swap agreements, approximately 4.6 million MMBtu, is at a weighted average NYMEX reference price of 6.52 Canadian dollars per MMBtu and will be settled in Canadian dollars. Additionally, the Company has entered into basis swap agreements for the approximately 4.2 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. The Company has also entered into an oil price swap agreement for the first quarter of 2004 covering 182,000 barrel at a weighted average NYMEX reference price of $28.97 per barrel.

The counter parties to the Company s current hedging agreements are commercial or investment banks. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

Relatively modest changes in either oil or gas prices significantly impact the Company s results of operations and cash flow. However, the impact of changes in the market prices for oil and gas on the Company s average realized prices may be reduced from time to time based on the level of the Company s hedging activities. Based on the oil production from continuing operations for the first six months of 2003, a change in the average oil price realized, before hedges, by the Company of $1.00 per Bbl would result in a change in net income and cash flow before income taxes on an annual basis of approximately $12.3 million and $19.5 million, respectively. A 10 cent per Mcf change in the average price realized, before hedges, by the Company would result in a change in net income and cash flow before income taxes on an annual basis of approximately $3.7 million and $5.9 million, respectively, based on gas production for the first six months of 2003.

Period to Period Comparison

The period to period comparisons presented below are significantly affected by dispositions made by the Company during the periods. On July 30, 2002, the Company completed the sale of its operations in Trinidad. The Company received $40 million in cash and recorded a gain of approximately $31.9 million ($14.9 million after income taxes). On January 31, 2003, the Company completed the sale of its operations in Ecuador. The Company received $137.4 million in cash and recorded a gain of approximately $47.3 million ($9.5 million after income taxes), subject to post-closing adjustments. In accordance with the rules established by Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the Company s operations in Trinidad and Ecuador, along with the gain on the sale of Ecuador, are accounted for as discontinued operations in the Company s consolidated financial statements. ***Accordingly, the revenues and operating expenses discussed below exclude the results related to the Company s operations in Ecuador and Trinidad for all periods.***

Three months ended June 30, 2003, compared to three months ended June 30, 2002

The Company reported a net loss of $8.7 million for the quarter ended June 30, 2003, compared to net income of $22.4 million for the same period in 2002. The net loss for the three months ended June 30, 2003, included:

- non-cash charges of $12.6 million ($7.3 million net of tax) for the impairment of certain producing oil and gas properties in Canada and $29.0 million ($17.0 million net of tax) for the impairment of certain exploration acreage, most of which is related to the Company s Canadian Northwest Territories project;

- foreign currency exchange losses of $3.5 million; and

- a gain on disposition of assets of $0.3 million ($0.2 million net of tax).

Net income for the second quarter of 2002 included:

- non-cash charges of $5.2 million ($3.1 million net of tax) for the impairment of certain exploration acreage;

- foreign currency exchange gains of $1.2 million;

- a net gain on dispositions of assets of $17.6 million ($10.8 million net of tax);

a loss on early extinguishment of debt of $8.2 million ($5.0 million net of tax); and

income from discontinued operations of $2.1 million ($1.6 million net of tax).

Oil and gas sales increased $6.8 million (four percent), to $159.5 million for the second quarter of 2003 from $152.7 million for the second quarter of 2002. Gas revenues increased by $5.6 million (13 percent) primarily as a result of a 43 percent increase in average gas prices, which more than offset a 21 percent decrease in gas production. Oil revenues increased by $1.2 million (one percent), primarily as a result of a 17 percent increase in average oil prices, which more than offset a 13 percent decrease in oil production from continuing operations. Production from continuing operations on an equivalent barrel basis decreased 16 percent resulting from the Company s property divestitures made in the United States in June 2002 and March 2003, natural production declines and the effects of substantially curtailed capital expenditures in 2002, which resulted in significantly lower production levels at the beginning of 2003. Capital expenditures in 2002 were limited to $129.7 million, or approximately 54 percent of cash flow provided by operating activities, as a result of the Company s decision to use a portion of cash flow and proceeds from asset sales to execute its debt reduction program during 2002.

Revenues and expenses for gas marketing increased significantly from the second quarter of 2002 to the second quarter of 2003 primarily due to an increase in U.S. gas prices.

A net gain on disposition of assets of $17.6 million ($10.8 million net of tax) was reflected in the second quarter of 2002 primarily as a result of the sale of the Company s heavy oil properties in the Santa Maria area of southern California in June 2002. The Company recorded a gain of approximately $18.3 million ($11.2 million net of tax) on this transaction. Included in the gain is a reversal of the Company s accrual for future abandonment costs related to these properties. Other than the gain recorded, this disposition did not significantly affect the Company s results of operations for the second quarter of 2002 as the sale occurred at the end of the quarter. The Company recorded a net gain on disposition of non-strategic assets in Canada of $0.3 million in the second quarter of 2003.

As discussed in Note 2 to the Company s consolidated financial statements included elsewhere in this Form 10-Q, the Argentine government took actions which, in effect, caused the devaluation of the peso in early December 2001. The translation of peso-denominated balances at March 31, 2002, and peso-denominated transactions during the three months ended June 30, 2002, resulted in a foreign currency exchange gain of $0.8 million on the statement of operations. The translation of peso-denominated balances at June 30, 2003, and peso-denominated transactions for the quarter ended June 30, 2003, resulted in a foreign currency exchange loss of $3.5 million. This loss was caused by the strengthening of the peso from a rate of 2.98 pesos to one U.S. dollar at March 31, 2003, to a rate of 2.82 pesos to one U.S. dollar at June 30, 2003.

Lease operating expenses, including production and export taxes, increased $0.4 million (one percent), to $54.3 million for the second quarter of 2003 from $53.9 million for the second quarter of 2002. On an equivalent barrel basis, lease operating expenses increased 20 percent from $6.53 for the second quarter of 2002 to $7.86 for the second quarter of 2003. Over 30 percent the increase on an equivalent barrel basis was attributable to higher costs (expressed in U.S. dollars) in Argentina and Canada resulting from peso inflation and the strengthening of the peso and the Canadian dollar. The increase on an equivalent barrel basis was also caused by declines in production. These increases were offset by a decline in the Argentina oil export tax of $1.9 million resulting from lower export volumes in the second quarter of 2003 compared to the second quarter of 2002.

Exploration costs increased by $25.4 million (363 percent), to $32.4 million for the second quarter of 2003 from $7.0 million for the second quarter of 2002. During the second quarter of 2003, the Company s exploration costs consisted of $29.5 million for leasehold impairments and unsuccessful exploratory drilling and $2.9 million for seismic and other geological and geophysical costs. Exploration expenses for the second quarter of 2002 consisted of $5.6 million for unsuccessful exploratory drilling and leasehold impairments and $1.4 million for seismic and other geological and geophysical costs. The leasehold impairments in the second quarter of 2003 include $23.7 million ($13.9 million net of taxes) related to the Company s Northwest Territories project in Canada. The Company recently completed its review of this project s exploration potential and, while it believes this project may contain significant exploration potential, it has determined that the project no longer fits the Company s current investment portfolio. No additional capital expenditures are planned and the Company is initiating efforts to farm out its position in this project.

General and administrative expenses increased $3.4 million (27 percent), to $15.9 million for the second quarter of 2003 from $12.5 million for the second quarter of 2002. Expenses increased primarily due to non-cash charges related to restricted stock awards, cash bonuses and Argentina asset taxes in the second quarter of 2003 with no comparable amounts in the second quarter of 2002. These increases, along with a 16 percent decline in production on an equivalent barrel basis, increased the Company s general and administrative expenses per equivalent barrel produced from $1.52 for the second quarter of 2002 to $2.30 for the second quarter of 2003.

Depreciation, depletion and amortization decreased $11.3 million (25 percent), to $34.8 million for the second quarter of 2003 from $46.1 million for the second quarter of 2002. The Company s average oil and gas amortization rate per equivalent barrel produced decreased from $5.59 in the second quarter of 2002 to $5.03 in the second quarter of 2003. These decreases primarily resulted from the impact that substantially higher product prices in 2003 had in increasing the proved reserves used to determine the amortization rate and, to a lesser degree, from the Company s mandated adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143), effective January 1, 2003. Previously, the Company accrued an undiscounted estimate of future abandonment costs of wells and related facilities through its depreciation calculation in accordance with the provisions of Statement of Financial Accounting Standards No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, (SFAS 19) and industry practice. With the implementation of SFAS 143, the Company has now recorded a discounted fair value of the future retirement obligation as a liability with a corresponding amount capitalized as part of the related property s carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset. The liability accretes over time with a charge to accretion expense, which was $1.8 million for the second quarter of 2003.

Interest expense decreased $2.7 million (13 percent) to $18.0 million for the second quarter of 2003 from $20.7 million for the second quarter of 2002 due to a 24 percent reduction in its average debt outstanding from the second quarter of 2002 to the second quarter of 2003. In May 2002, the Company issued $350 million of its 8 1/4% Senior Notes due 2012 (the 8 1/4% Notes). All of the net proceeds were used to repay a portion of the outstanding balance under the Company s revolving credit facility and to redeem $100 million of the Company s outstanding 9% Senior Subordinated Notes due 2005 (the 9% Notes). In conjunction with the issuance of the 8 1/4% Notes, the Company was required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% Notes, resulted in a charge of approximately $8.2 million ($5.0 million net of tax) in the second quarter of 2002.

The Company recorded an impairment of $12.6 million ($7.3 million net of tax) in the second quarter of 2003 related to certain producing oil and gas properties in Canada. These impairments were caused by negative reserve revisions as a result of unsuccessful workover operations and additional technical evaluation of other non-producing projects. There were no impairments of oil and gas producing properties recorded in the second quarter of 2002.

Six months ended June 30, 2003, compared to six months ended June 30, 2002

The Company reported net income of $32.0 million for the six months ended June 30, 2003, compared to a net loss of $43.7 million for the same period in 2002. Net income for first half of 2003 included:

- non-cash charges of $12.6 million ($7.3 million net of tax) for the impairment of certain producing oil and gas properties in Canada and $31.2 million ($25.6 million net of tax) for the impairment of certain exploration acreage, most of which is related to the Company s Canadian Northwest Territories project;
- foreign currency exchange losses of $7.2 million;
- a net loss on dispositions of assets of $0.3 million ($0.2 million net of tax);
- a loss on early extinguishment of debt of $1.4 million ($0.9 million net of tax);
- income from discontinued operations of $49.1 million ($10.8 million net of tax); and
- the positive impact of a cumulative effect of a change in accounting principal of $11.2 million ($7.1 million net of tax).

Net income for the first half of 2002 included:

- non-cash charges of $8.6 million ($5.1 million net of tax) for the impairment of certain exploration acreage;
- foreign currency exchange gains of $4.1 million;
- a net gain on dispositions of assets of $17.7 million ($10.8 million net of tax);
- a loss on early extinguishment of debt of $8.2 million ($5.0 million net of tax);
- income from discontinued operations of $2.9 million ($2.3 million net of tax); and
- the negative impact of a cumulative effect of a change in accounting principal of $60.5 million.

Oil and gas sales increased $74.0 million (27 percent), to $345.2 million for the first six months of 2003 from $271.2 million for the first six months of 2002. Oil revenues increased by $41.4 million (21 percent), primarily as a result of a 42 percent increase in average oil prices, which more than offset a 15 percent decrease in oil production. Similarly, gas revenues increased by $32.6 million (44 percent) primarily as a result of a 68 percent increase in average gas prices, which more than offset a 15 percent decrease in gas production. Production on an equivalent barrel basis decreased 15 percent resulting from the Company s property divestitures made in the United States in June 2002 and March 2003, natural production declines and the effects of substantially curtailed capital expenditures in 2002, which resulted in significantly lower production levels at the beginning of 2003. 2003. Capital expenditures in 2002 were limited to $129.7 million, or approximately 54 percent of cash flow provided by operating activities, as a result of the Company s decision to use a portion of cash flow and proceeds from asset sales to execute its debt reduction program during 2002.

Revenues and expenses for gas marketing increased significantly from the first six months of 2002 to the first six months of 2003 primarily due to an increase in U.S. gas prices.

A net gain on disposition of assets of $17.7 million ($10.8 million net of tax) was reflected in the first six months of 2002 primarily due to the sale of the Company s heavy oil properties in the Santa Maria area of southern California in June 2002. The Company recorded a gain of approximately $18.3 million ($11.2 million net of tax) on this transaction. Included in the gain is a reversal of the Company s accrual for future abandonment costs related to these properties. Other than the gain recorded, this disposition did not significantly affect the Company s results of operations for the first half of 2002 as the sale occurred at the end of the period. The Company recorded a net loss on disposition of assets of $0.3 million in the first six months of 2003.

The translation of peso-denominated balances at June 30, 2002, and peso-denominated transactions during the six months ended June 30, 2002, resulted in a foreign currency exchange gain of $3.7 million on the statement of operations. The Company also recorded a gain of $0.9 million in Other income for the six months of 2002 related to the Argentine government-mandated negotiated settlement of U.S. dollar-denominated receivables and payables in existence at January 6, 2002. The translation of peso-denominated balances at June 30, 2003, and peso-denominated transactions for the six months ended June 30, 2003, resulted in a foreign currency exchange loss of $7.6 million. This loss was caused by the strengthening of the peso from a rate of 3.38 pesos to one U.S. dollar at December 31, 2002, to a rate of 2.82 pesos to one U.S. dollar at June 30, 2003. This loss was partially offset by a $0.4 million gain resulting from certain transactions related to the Company s Canadian operations that are denominated in U.S. dollars.

Lease operating expenses, including production and export taxes, increased $7.8 million (eight percent), to $108.5 million for the first six months of 2003 from $100.7 million for the first six months of 2002. On an equivalent barrel basis, lease operating expenses increased 26 percent from $6.17 for the first six months of 2002 to $7.78 for the first six months of 2003. The tax imposed on Argentine oil exports beginning at the end of the first quarter of 2002 increased lease operating expenses by $7.8 million ($0.56 per equivalent barrel) for the first six months of 2002 compared to the first six months of 2003. Lease operating expenses per equivalent barrel, before the impact of the Argentina export tax, increased by 17 percent from $5.52 for the first six months of 2002 to $6.46 for the first six months of 2003. The increase was primarily the result of higher costs (expressed in U.S. dollars) in Argentina and Canada resulting from peso inflation and the strengthening of the peso and the Canadian dollar and by declines in production.

Exploration costs increased by $30.5 million (191 percent), to $46.5 million for the first six months of 2003 from $16.0 million for the first six months of 2002. During the first half of 2003, the Company s exploration costs included $41.4 million for leasehold impairments and unsuccessful exploratory drilling and $5.1 million for seismic and other geological and geophysical costs. Exploration expenses for the first half of 2002 consisted of $11.0 million for unsuccessful exploratory drilling and leasehold impairments and $5.0 million for seismic and other geological and geophysical costs. The leasehold impairments in the first half of 2003 include $23.7 million ($13.9 million net of taxes) related to the Company s Northwest Territories project in Canada.

General and administrative expenses increased $5.2 million (21 percent), to $30.3 million for the first six months of 2003 from $25.1 million for the first six months of 2002. Expenses increased primarily due to non-cash charges related to restricted stock awards, cash bonuses and Argentina asset taxes in the first half of 2003 with no comparable amounts in the first half of 2002. These increases, along with a 15 percent decline in production on an equivalent barrel basis, increased the Company s general and administrative expenses per equivalent barrel produced from $1.53 for the first half of 2002 to $2.17 for the first half of 2003.

Depreciation, depletion and amortization decreased $23.2 million (24 percent), to $72.1 million for the first six months of 2003 from $95.3 million for the first six months of 2002. The Company s average oil and gas amortization rate per equivalent barrel produced decreased from $5.84 in the first half of 2002 to $5.17 in the first half of 2003. These decreases primarily resulted from the impact that substantially higher product prices in 2003 had in increasing proved reserves used to determine the amortization rate and, to a lesser degree, from the Company s mandated adoption of SFAS 143, effective January 1, 2003. Previously, the Company accrued an undiscounted estimate of future abandonment costs of wells and related facilities through its depreciation calculation in accordance with the provisions of SFAS 19 and industry practice. With the implementation of SFAS 143, the Company has now recorded a discounted fair value of the future retirement obligation as a liability with a corresponding amount capitalized as part of the related property s carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset. The liability accretes over time with a charge to accretion expense, which was $3.6 million for the first half of 2003. As a result of the implementation of SFAS 143, the Company recorded a non-cash gain as a cumulative effect of change in accounting principle of $7.1 million, net of taxes of $4.1 million.

Interest expense decreased $1.6 million (four percent) to $36.6 million for the first six months of 2003 from $38.2 million for the first six months of 2002 due to a 22 percent reduction in its average debt outstanding from the first half of 2002 to the first half of 2003. In May 2002, the Company issued $350 million of its 8 $^{1}/4$% Notes. All of the net proceeds were used to repay a portion of the outstanding balance under the Company s revolving credit facility and to redeem $100 million of the Company s 9% Notes.

In conjunction with the issuance of its 8 $^{1}/4$% Notes, the Company redeemed a portion of its 9% Notes. The Company was required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% Notes, resulted in a charge of approximately $8.2 million ($4.3 million net of tax) in the first half of 2002. During the first six months of 2003, the Company advanced funds under its revolving credit facility to redeem the remainder of its 9% Notes. As a result, the Company was required to expense the remaining associated deferred financing costs and discounts. This $0.7 million non-cash charge and a $0.7 million cash charge for the call premium on the redemption of the remaining 9% Notes in 2003 resulted in a charge of approximately $1.4 million ($0.9 million net of tax).

The Company recorded an impairment of $12.6 million ($7.3 million net of tax) in the first six months of 2003 related to certain producing oil and gas properties in Canada. These impairments were caused by negative reserve revisions as a result of unsuccessful workover operations and additional technical evaluation of other non-producing projects. There were no impairments of oil and gas producing properties recorded in the first six months of 2002.

Effective January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (SFAS 142). SFAS 142 changed the accounting for goodwill from an amortization method to an impairment-only method. Goodwill was tested for impairment in conjunction with a transitional goodwill impairment test in 2002. As a result of the transitional impairment test, the Company recorded a $60.5 million charge as a cumulative effect of change in accounting principle retroactive to January 1, 2002, in accordance with the provisions of SFAS 142. No similar charge was required in 2003.

Capital Expenditures

During the first six months of 2003, the Company s total oil and gas capital expenditures were $78.8 million ($77.7 million for continuing operations). In North America, the Company s oil and gas capital expenditures totaled $47.9 million. Exploitation activities accounted for $24.9 million of the North America capital expenditures with exploration activities contributing $23.0 million. During the first six months of 2003, the Company s international oil and gas capital expenditures totaled $30.9 million. This amount includes $20.7 million for exploitation activities, of which $19.6 million was spent in Argentina and $1.1 million was spent in Ecuador. Exploration spending of $10.2 million consisted of $8.3 million in Yemen, $1.3 million in Bolivia and $0.6 million in various other areas.

As of June 30, 2003, the Company had total unproved oil and gas property costs of approximately $71.2 million, consisting of undeveloped leasehold costs of $52.4 million, including $39.2 million in Canada, and unproved exploratory drilling costs of $18.8 million. Approximately $21.8 million of the total unproved costs are associated with the Company s drilling program in Yemen. Results of certain long-term production tests in Yemen are being incorporated into the technical and economic evaluation that the Company is performing to determine commercial viability of its Yemen project. If the results of this evaluation support development, the Company will pursue the declaration of commerciality and approval of a plan of development before the end of 2003. In the second quarter of 2003, the Company recorded additional exploration expense of $23.7 million ($13.9 million net of tax) to fully impair its undeveloped leaseholds in the Northwest Territories. Future exploration expense and earnings may be impacted to the extent that the Company s future exploration activities are unsuccessful in discovering commercial oil and gas reserves in sufficient quantities to recover its costs.

The timing of most of the Company s capital expenditures is discretionary with no material long-term capital expenditure commitments. Consequently, the Company has a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. The Company uses internally-generated cash flows to fund capital expenditures other than significant acquisitions. The Company s capital expenditure budget for 2003 is currently set at $185 million, exclusive of acquisitions. The Company does not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. The Company is actively pursuing additional acquisitions of oil and gas properties. In addition to cash on hand, internally-generated cash flow and advances under its revolving credit facility, the Company may seek additional sources of capital to fund any future significant acquisitions (see Capital Resources and Liquidity); however, no assurance can be given that sufficient funds will be available to fund the Company s desired acquisitions.

Capital Resources and Liquidity

Cash on hand, internally generated cash flow and the borrowing capacity under its revolving credit facility are the Company s major sources of liquidity. The Company also has the ability to adjust its level of capital expenditures. The Company may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions it might secure in the future and to maintain its financial flexibility.

In the past, the Company has accessed the public markets to finance significant acquisitions and provide liquidity for its future activities. Since 1990, the Company has completed five public equity offerings as well as two public debt offerings and three Rule 144A private debt offerings, all of which have provided the Company with aggregate net proceeds of approximately $1.2 billion.

On May 2, 2002, the Company issued, through a Rule 144A offering, $350 million of its 8 1/4% Notes. All of the net proceeds were used to repay a portion of the outstanding balance under the Company s revolving credit facility and to redeem $100 million of the Company s outstanding 9% Notes. The 8 1/4% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after May 1, 2007. In addition, prior to May 1, 2005, the Company may redeem up to 35 percent of the 8 1/4% Notes with the proceeds of certain underwritten public offerings of the Company s common stock. The 8 1/4% Notes mature on May 1, 2012, with interest payable semi-annually on May 1 and November 1 of each year.

In conjunction with the offering of 8 1/4% Notes, the Company entered into a new $300 million revolving credit facility (as amended, the Bank Facility), which was used to refinance its previously existing credit facility and to provide funds for ongoing operating and general corporate needs.

During the first quarter of 2003, the Company advanced funds under the Bank Facility to redeem the remainder of the 9% Notes. As a result, the Company was required to expense certain associated deferred financing costs and discounts. This $0.7 million non-cash charge and a $0.7 million cash charge for the call premium on the redemption of the remaining 9% Notes resulted in a one-time charge of approximately $1.4 million ($0.9 million net of tax).

The Bank Facility consists of a three-year senior secured credit facility with availability governed by a borrowing base determination. The Company s availability under the Bank Facility is reduced by the outstanding letters of credit. The borrowing base (currently $300 million) is based on the banks evaluation of the Company s oil and gas reserves. The amount available to be borrowed under the Bank Facility is limited to the lesser of the borrowing base or the facility size, which is also currently set at $300 million. The next semi-annual borrowing base redetermination will be in November 2003. The Bank Facility is secured by a first priority lien on the Company s U.S. oil and gas properties constituting at least 80 percent of the present value of the Company s U.S. proved reserves owned now or in the future. The Bank Facility will be guaranteed by any of the Company s existing and future U.S. subsidiaries that grant a lien on oil and gas properties under the Bank Facility.

Outstanding advances under the Bank Facility bear interest payable quarterly at a floating rate based on Bank of Montreal s alternate base rate (as defined) or, at the Company s option, at a fixed rate for up to six months based on the Eurodollar market rate (LIBOR). The Company s interest rate increments above the alternate base rate and LIBOR vary based on the level of outstanding senior debt to the borrowing base. In addition, the Company must pay a commitment fee of 0.50 percent per annum on the unused portion of the banks commitment. Unused availability under the Bank Facility is currently $299.0 million, considering outstanding letters of credit of $1.0 million.

The terms of the Bank Facility require the maintenance of a minimum current ratio (as defined therein) and tangible net worth (as defined therein) of not less than $425 million plus 75 percent of the net proceeds of any future equity offerings less any impairment write downs required by GAAP or by the Securities and Exchange Commission and excluding any impact related to SFAS 133.

The Company s internally generated cash flows, results of operations and financing for its operations are dependent on oil and gas prices. Realized oil and gas prices for the first six months of 2003 increased by 42 percent and 68 percent, respectively, as compared to the same period in 2002. For the first six months of 2003, approximately 64 percent of the Company s production was oil. The Company believes that its cash on hand, cash flows and unused availability under the Bank Facility are sufficient to fund its planned capital expenditures for the foreseeable future. To the extent oil and gas prices decline, the Company s earnings and cash flows from operations may be adversely impacted. Prolonged periods of low oil and gas prices could cause the Company to not be in compliance with maintenance covenants under its Bank Facility and could negatively affect its credit statistics and coverage ratios and thereby affect its liquidity.

Consistent with its stated goal of maintaining financial flexibility and optimizing its portfolio of assets, the Company announced in early 2002 plans to reduce debt by $200 million through a combination of asset sales and cash flows in excess of planned capital expenditures. The Company s operations in Ecuador were sold in January 2003 for $137.4 million in cash, subject to post-closing adjustments. The closing of this sale culminated the achievement of the Company s $200 million debt reduction goal. In addition, the Company sold certain non-strategic U.S. assets on March 31, 2003, for approximately $29.5 million and certain non-strategic assets in Canada for approximately 14.9 million Canadian dollars in June 2003. The Company also sold certain other non-strategic assets in Canada for approximately 24.2 million Canadian dollars in July 2003. The Company has no current plans for further asset divestitures in 2003.

Contractual Obligations

The Company s contractual obligations have not changed significantly since December 31, 2002, except for the following:

- during the first quarter of 2003, the Company advanced funds under the Bank Facility to redeem the remaining $50.0 million principal balance of the 9% Notes;
- a portion of the proceeds from the January 2003 sale of the Company s operations in Ecuador were used to repay the outstanding balance under the Bank Facility;
- the remaining Bolivia work unit commitments have been fulfilled;
- the amount of outstanding letters of credit issued by commercial banks on the Company s behalf declined to $9.7 million at June 30, 2003, and to $1.0 million at July 31, 2003; and
- the Company has future minimum long-term electric power purchase commitments in Argentina of $0.9 million for the remainder of 2003, $3.6 million in 2004, $3.6 million in 2005 and $7.6 million in 2006.

Inflation

As a result of the devaluation of the Argentine peso, 2002 peso inflation was approximately 41 percent in Argentina. However, in recent months, the Argentine inflation rate has slowed significantly, with the inflation rate for the first half of 2003 at less than three percent. In recent years, inflation outside of Argentina has not had a significant impact on the Company s operations or financial condition and is not currently expected to have a significant impact on future periods.

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Income Taxes

The Company incurred a current provision for income taxes related to continuing operations of approximately $30.8 million and $11.8 million for the first six months of 2003 and 2002, respectively. The total provision for U.S. income taxes is based on the federal corporate statutory income tax rate plus an estimated average rate for state income taxes. Earnings of the Company s foreign subsidiaries are subject to foreign income taxes. No U.S. deferred tax liability will be recognized related to the unremitted earnings of these foreign subsidiaries, as it is the Company s intention, generally, to reinvest such earnings permanently.

A reconciliation of the U.S. federal statutory income tax rate to the effective rate for continuing operations is as follows:

	Six Months Ended June 30,	
	2003	2002
U.S. federal statutory income tax rate	35.0%	35.0%
U.S. state income tax (net of federal tax benefit)	1.6	0.6
Foreign operations	13.2	(30.1)
U.S. permanent differences	0.9	1.0
	50.7%	6.5%

The impact of foreign operations for the first half of 2002 is primarily the result of the Company s impairment of its goodwill related to its Canadian operations which is not deductible for income tax purposes. As the Company was in a net loss position for the period, this non-deductible expense had the effect of reducing the Company s net tax benefit and its overall effective tax rate.

The impact of foreign operations for the first half of 2003 is primarily the continuing effect of the peso devaluation on the Company s Argentine tax balance sheet due to the inability, to date, to utilize inflation accounting for fixed assets and the unfavorable Argentine tax impact on U.S. dollar-denominated liabilities due to the strengthening of the peso in the first half of 2003.

The income tax expense related to the gain on the sale of operations in Ecuador shown in discontinued operations includes $19.4 million of taxes on previously unremitted foreign earnings. No U.S. income taxes were previously recorded on these earnings.

Critical Accounting Policies

The Company s critical accounting policies are discussed in its 2002 Annual Report on Form 10-K (the Annual Report), Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations. There have been no material changes in the Company s critical accounting policies from those reported in the Annual Report.

Changes in Accounting Principles

On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, *Business Combinations* (SFAS 141), and SFAS 142. SFAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS 142, goodwill is no longer subject to amortization. Instead, goodwill will be subject to at least an annual assessment for impairment by applying a fair-value based test. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer s intent to do so.

The Company adopted SFAS 141 and SFAS 142 effective January 1, 2002, resulting in the elimination of goodwill amortization from statements of operations in future periods. As discussed in Note 5 to the Company s consolidated financial statements included elsewhere in this Form 10-Q, the Company recorded an impairment charge of $60.5 million related to the goodwill of its Canadian operations as a cumulative effect of a change in accounting principle in its statement of operations.

In August 2001, FASB issued SFAS 143. The Company was required to adopt this new standard beginning January 1, 2003. Through December 31, 2002, the Company accrued an estimate of future abandonment costs of wells and related facilities through its depreciation calculation and included the cumulative accrual in accumulated depreciation in accordance with the provisions of SFAS 19 and industry practice. At December 31, 2002, approximately $54.6 million of accrued future abandonment costs were included in accumulated depreciation. The new standard requires that the Company record the discounted fair value of the retirement obligation as a liability at the time a well is drilled or acquired. The majority of the asset retirement obligations of the Company relate to the plugging and abandonment of oil and gas wells, site reclamation and facilities dismantlement. However, future abandonment liabilities were also recorded for other assets such as pipelines, processing plants and compressors. A corresponding amount is capitalized as part of the related property s carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset. The liability accretes over time with a charge to accretion expense. At January 1, 2003, there were no assets legally restricted for purposes of settling asset retirement obligations.

The Company adopted the new standard effective January 1, 2003, and recorded an increase in property, plant and equipment of approximately $50.3 million, a decrease in accumulated depreciation, depletion and amortization of approximately $43.9 million, an increase in current asset retirement liabilities of approximately $4.5 million, an increase in long-term asset retirement liabilities of approximately $78.5 million, a $4.1 million increase in deferred income tax liabilities and a non-cash gain as a result of the cumulative effect of change in accounting principle, net of tax, of approximately $7.1 million.

On January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). SFAS 144 creates accounting and reporting standards to establish a single accounting model, based on the framework established in Statement of Financial Accounting Standards No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of* (SFAS 121), for long-lived assets to be disposed of by sale. The adoption of SFAS 144 did not have a material impact on the Company s financial position or results of operations.

On April 30, 2002, the FASB issued Statement of Financial Accounting Standards No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections* (SFAS 145). SFAS 145 updates, clarifies and simplifies existing accounting pronouncements. Among other items, it rescinds previous accounting rules which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. The Company has adopted the provisions of SFAS 145 and, accordingly, has classified charges of $1.4 million ($0.9 million net of tax) and $8.2 million ($4.3 million net of tax) in 2003 and 2002, respectively, for losses on the early extinguishment of debt as charges to income from continuing operations in its statements of operations. The adoption of SFAS 145 did not have any other material impact on the Company s financial position or results of operations.

On July 30, 2002, the FASB issued Statement of Financial Accounting Standards No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The provisions of this statement are to be applied prospectively to exit or disposal activities initiated after December 31, 2002. The adoption of this standard did not have a material impact on the Company s financial position or results of operations.

On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure* (SFAS 148). SFAS 148 amends Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), to provide alternative methods of transition to SFAS 123 s fair value method of accounting for stock-based employee compensation. SFAS 148 also amends the disclosure provisions of SFAS 123 and APB Opinion No. 28, *Interim Financial Reporting*, to require disclosure in the summary of significant accounting policies of the effects of an entity s accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. While SFAS 148 does not require companies to account for employee stock options using the fair value method, the disclosure provisions of the standard are applicable to all companies with stock-based employee compensation, regardless of whether they account for that compensation using the fair value method or the intrinsic value method. The Company has adopted the disclosure provisions of SFAS 148. The Company is considering the adoption of SFAS 123 s fair value method of accounting for stock-based employee compensation in 2003, but has not yet made a final determination.

New Accounting Pronouncements

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51* (FIN 46). FIN 46 requires the consolidation of entities in which an enterprise absorbs a majority of the entity s expected losses, receives a majority of the entity s expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority of voting interest in the entity. The Company expects FIN 46 to have no impact on its financial position or results of operations.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS 149). SFAS 149 is intended to result in more consistent reporting of contracts as either freestanding derivative instruments subject to SFAS 133 in its entirety, or as hybrid instruments with debt host contracts and embedded derivative features. SFAS 149 is effective for contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003. The Company does not expect the adoption of SFAS 149 to have a material impact on its financial position or results of operations.

On May 15, 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS 150). SFAS 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. SFAS 150 must be applied immediately to instruments entered into or modified after May 31, 2003, and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. Early adoption of SFAS 150 is not permitted. The Company does not expect the adoption of SFAS 150 to have a material impact on its financial position or results of operations.

Foreign Operations

For information on the Company s foreign operations, see Item 3. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk included elsewhere in this Form 10-Q.

Forward-Looking Statements

This Form 10-Q includes certain statements that may be deemed to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements in this Form 10-Q, other than statements of historical facts, that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future, including production, operating costs and product price realizations, future capital expenditures (including the amount and nature thereof), the drilling of wells, reserve estimates, future production of oil and gas, future cash flows, future reserve activity, planned asset sales or dispositions, events or developments in Argentina, including estimates of oil export levels, and other such matters are forward-looking statements. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions within the bounds of its knowledge of its business, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements.

Factors that could cause actual results to differ materially from those in forward-looking statements include: oil and gas prices; exploitation and exploration successes; actions taken and to be taken by Argentina as a result of its economic condition; continued availability of capital and financing; general economic, market or business conditions; acquisition and other business opportunities (or lack thereof) that may be presented to the Company; changes in laws or regulations; risk factors listed from time to time in the Company s reports and other documents filed with the Securities and Exchange Commission; and other factors. The Company assumes no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company s operations are exposed to market risks primarily as a result of changes in commodity prices, interest rates and foreign currency exchange rates. The Company does not use derivative financial instruments for speculative or trading purposes.

Commodity Price Risk

The Company produces, purchases and sells crude oil, natural gas, condensate, natural gas liquids and sulfur. As a result, the Company s financial results can be significantly impacted as these commodity prices fluctuate widely in response to changing market forces. See Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the impact of commodity price changes based on production levels for the first six months of 2003. The Company has previously engaged in oil and gas hedging activities and intends to continue to consider various hedging arrangements to realize commodity prices which it considers favorable.

As of June 30, 2003, the Company has entered into various oil price swap agreements for various periods of the remainder of 2003 covering approximately 1.8 million barrels at a weighted average NYMEX reference price of $24.98 per barrel and gas price swap agreements for various periods of the remainder of 2003 covering approximately 10.1 million MMBtu. The U.S. portion of the gas swap agreements, approximately 5.5 million MMBtu, is at a weighted average NYMEX reference price of $3.96 per MMBtu. The Canadian portion of the gas swap agreements, approximately 4.6 million MMBtu, is at a weighted average NYMEX reference price of 6.52 Canadian dollars per MMBtu. Additionally, the Company has entered into basis swap agreements for the approximately 4.2 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. At June 30, 2003, the Company would have paid approximately $19.7 million to terminate its swap agreements then in place. Subsequent to June 30, 2003, the Company entered into additional oil price swap agreements for various periods of the remainder of 2003 for 611,000 barrels at a weighted average NYMEX reference price of $30.41 per barrel and for the first quarter of 2004 for 182,000 barrels at a weighted average NYMEX reference price of $28.97 per barrel.

The counterparties to the Company s hedging agreements are commercial or investment banks. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

Interest Rate Risk

The Company s interest rate risk exposure results primarily from short-term rates, mainly LIBOR-based, on borrowings from its commercial banks. To reduce the impact of fluctuations in interest rates, the Company has historically maintained a portion of its total debt portfolio in fixed-rate debt. At June 30, 2003, substantially all of the Company s outstanding debt was at fixed rates. However, the Company expects that this relationship will not continue and that a portion of the Company s debt in future periods will be at variable rates. In the past, the Company has not entered into financial instruments such as interest rate swaps or interest rate lock agreements. However, it may consider these instruments to manage the portfolio mix between fixed and floating rate debt and to mitigate the impact of changes in interest rates based on management s assessment of future interest rates, volatility of the yield curve and the Company s ability to access the capital markets in a timely manner.

Based on the limited amount of outstanding borrowings under variable-rate debt instruments as of June 30, 2003, a change in the average interest rate of 100 basis points would have resulted in no substantial change in net income and cash flows before income taxes.

The following table provides information about the Company s long-term debt principal payments and weighted-average interest rates by expected maturity dates:

Long-term Debt:	**2003**	**2004**	**2005**	**2006**	**2007**	**There-after**	**Total**	**Fair Value at 6/30/03**
Fixed rate (in thousands)						$ 800,000	$ 800,000	$ 856,125
Average interest rate						8.5%	8.5%	
Variable rate (in thousands)			$ 3,100				$ 3,100	$ 3,100
Average interest rate			(a)				(a)	(a)

(a) LIBOR plus an increment based on the level of outstanding senior debt to the borrowing base, up to a maximum increment of 2.25 percent. Current increment above LIBOR at June 30, 2003, was 1.25 percent.

Foreign Currency and Operations Risk

International investments represent, and are expected to continue to represent, a significant portion of the Company s total assets. The Company has international operations in Canada, Argentina, Bolivia, Yemen and Italy. For the six months ended June 30, 2003, the Company s operations in Argentina and Canada accounted for approximately 34 percent and 16 percent, respectively, of the Company s revenues and, approximately 28 percent and 32 percent, respectively, of the Company s total assets. During the first six months of 2003 and at June 30, 2003, the Company s operations in Argentina and Canada represented its only foreign operations accounting for more than 10 percent of its revenues or total assets. The Company continues to identify and evaluate international opportunities, but currently has no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, the Company s financial results could be affected by factors such as changes in foreign currency exchange rates, weak economic conditions or changes in the political climate in these foreign countries.

Historically, the Company has not used derivatives or other financial instruments to hedge the risk associated with the movement in foreign currencies. However, the Company evaluates currency fluctuations and will consider the use of derivative financial instruments or employment of other investment alternatives if it deems cash flows or investment returns so warrant.

The Company s international operations, properties or investments may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors. For example:

local political and economic developments could restrict or increase the cost of the Company s foreign operations;

exchange controls and currency fluctuations could result in financial losses;

royalty and tax increases and retroactive claims could increase costs of the Company s foreign operations;

expropriation of the Company s property could result in loss of revenue, property and equipment;

civil uprisings, riots and war could make it impractical to continue operations, adversely affect both budgets and schedules and expose the Company to losses;

import and export regulations and other foreign laws or policies could result in loss of revenues;

repatriation levels for export revenues could restrict the availability of cash to fund operations outside a particular foreign country; and

laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict the Company s ability to fund foreign operations or may make foreign operations more costly.

The Company does not currently maintain political risk insurance. However, the Company will consider obtaining such coverage in the future if it deems conditions so warrant.

Canada. The Company views the operating environment in Canada as stable and the economic stability as good. Substantially all of the Company s Canadian revenues and costs are denominated in Canadian dollars. While the value of the Canadian dollar does fluctuate in relation to the U.S. dollar, the Company believes that any currency risk associated with its Canadian operations would not have a material impact on the Company s results of operations. The exchange rate at June 30, 2003, was US$1:C$1.35 as compared to US$1:C$1.58 at December 31, 2002.

Argentina. Beginning in 1991, Peronist Carlos Menem, as newly-elected President of Argentina, and Domingo Cavallo, as Minister of Economy, set out to reverse economic decline through free market reforms such as open trade. The key to their plan was the Law of Convertibility under which the peso was tied to the U.S. dollar at a rate of one peso to one U.S. dollar. Between 1991 and 1997 the plan succeeded. With the risk of devaluation apparently removed, capital came in from abroad and much of Argentina s state-owned assets were privatized. During this period, the economy grew at an annual average rate of 6.1 percent, the highest in the region.

However, the convertibility plan left Argentina with few monetary policy tools to respond to outside events. A series of external shocks began in 1998: prices for Argentina s commodities stopped rising; the dollar appreciated against other currencies; and Brazil, Argentina s main trading partner, devalued its currency. Argentina began a period of economic deflation, but failed to respond by reforming government spending. During 2001, Argentina s budget deficit exceeded $9 billion and its sovereign debt reached $140 billion.

As a result of economic instability and substantial withdrawals from the banking system, in early December 2001, the Argentine government, with Fernando de la Rua as President and Domingo Cavallo as Minister of Economy, instituted restrictions that prohibit foreign money transfers without Central Bank approval and limit cash withdrawals from bank accounts for personal transactions in small amounts with certain limited exceptions. While the legal exchange rate remained at one peso to one U.S. dollar, financial institutions were allowed to conduct only limited activity due to these controls, and currency exchange activity was effectively halted except for personal transactions in small amounts.

In late December 2001, as a result of political riots and upheaval in response to the banking restrictions, Fernando de la Rua was removed as president and the government was left in the hands of the Peronist controlled congress. Peronist Adolfo Rodriguez Saa, governor of San Luis province was named as the transitional president and held power for one week. During this time he announced default on Argentina s $140 billion sovereign debt.

In early January 2002, congress conferred power to Peronist Eduardo Duhalde, who enacted temporary measures intended to achieve economic stability and avoid default on multilateral debts. In addition, Duhalde set in motion a plan to transition the government back into the hands of an elected president on May 25, 2003, approximately six months ahead of the congressional mandate.

On January 6, 2002, the Argentine government abolished the one peso to one U.S. dollar legal exchange rate. On January 9, 2002, Decree 71 created a dual exchange market whereby foreign trade transactions were conducted at an official exchange rate of 1.4 pesos to one U.S. dollar and other transactions were conducted in a free floating exchange market. On February 8, 2002, Decree 260 unified the dual exchange markets and allowed the peso to float freely with the U.S. dollar. The exchange rate at June 30, 2003, was 2.82 pesos to one U.S. dollar. The devaluation of the peso reduced the Company s gas revenues and peso-denominated costs. The Company s oil revenues remain valued on a U.S. dollar basis.

On February 3, 2002, Decree 214 required all contracts that were previously payable in U.S. dollars to be payable in pesos. Pursuant to an emergency law passed on January 10, 2002, U.S. dollar obligations between private parties due after January 6, 2002, were liquidated in pesos at a negotiated rate of exchange which reflected a sharing of the impact of the devaluation. The Company s settlements in pesos of the existing U.S. dollar-denominated agreements were completed in the first half of 2002 and future periods will not be impacted by this mandate. This government-mandated equitable sharing of the impact of the devaluation resulted in a reduction in oil revenues from domestic sales for the first half of 2002 of approximately $8 million, ($1.37 per Argentine barrel produced or $0.73 per total Company barrel produced). The reduction of the Company s Argentine lease operating costs, which were also reduced as a result of this mandate and the positive impact of devaluation on the Company s peso-denominated costs, essentially offset the negative impact on Argentine oil revenues.

On February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. The tax of 20 percent is applied on the sales value after the tax, thus the net effect is 16.7 percent. The Company currently exports approximately 70 percent of its Argentine oil production. The Company believes that this export tax has and will continue to have the effect of decreasing all future Argentine oil revenues (not only export revenues) by the tax rate for the duration of the tax. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved to parity with the U.S. dollar denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings resulting from the devaluation of the peso on peso denominated costs and is further reduced by the Argentine income tax savings related to deducting the impact of the export tax. The export tax is not deducted in the calculation of royalty payments.

Since May 2002, many of Argentina s important economic indicators have stabilized. The Central Bank s foreign currency reserves have risen from a low of $8.9 billion in 2002 to a recent high on July 16, 2003, of $12.2 billion. Since being allowed to freely float against the U.S. dollar, the peso reached its weakest value at 3.80 pesos to one U.S. dollar in June of 2002, and has since stabilized, gradually appreciating to a value of 2.93 pesos to one U.S. dollar on August 6, 2003. Monthly inflation has decreased from a high of 10 percent for the month of April 2002 to an average of less than two percent per month from May to December 2002 with inflation for the first half of 2003 at less than three percent. Inflation for all of 2002 was approximately 41 percent.

After a year of negotiations, the International Monetary Fund (IMF) approved a $6.8 billion debt rollover agreement on January 24, 2003. While only short term in nature, the package was designed to allow stability through the presidential election process in May 2003 by rescheduling all IMF debts falling due between January and August of 2003. As part of the package, the government agreed to raise its primary budget surplus target to 2.5 percent of the country s gross domestic product.

On January 2, 2003, at the Argentine government s request, crude oil producers and refiners agreed to limit amounts payable for domestic sales occurring during the first quarter of 2003 to a maximum $28.50 per Bbl. The producers and refiners further agreed that the difference between the actual price and the maximum price would be payable once actual prices fall below the maximum. The debt payable under the agreement accrues interest at eight percent. The total debt will be collected by invoicing future deliveries at $28.50 per Bbl after actual prices fall below the maximum price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for ten consecutive days, which occurred on February 24, 2003.

On February 25, 2003, the agreement between the producers and the refiners was modified to limit the amount payable from refiners to producers for deliveries occurring between February 26, 2003, and March 31, 2003. While the $28.50 per Bbl payable maximum was maintained, under the modified terms refiners have no obligation to pay producers for sales values that exceed $36.00 per Bbl. Furthermore, interest for debts established during this period was reduced to seven percent. On April 11, 2003, the agreement was extended until May 31, 2003. On June 5, 2003, the agreement was further extended until July 31, 2003. The Company believes that, in the near future, the agreement will be further extended to September 30, 2003.

The Company sold approximately 660,000 net Bbls of its Argentine oil production under this agreement in the first six months of 2003. The Company has not recorded revenue for any amounts above the $28.50 per barrel maximum that have not yet been received. Repayments received from refiners will be recorded as revenues when received.

The plan set in motion by President Duhalde to transition the government back into the hands of an elected president was successfully completed during May 2003. General elections were held on April 27, 2003, and a runoff election between the top two candidates, former president Carlos Menem and current governor of Santa Cruz province, Nestor Kirchner were scheduled for May 18, 2003. Menem withdrew from the race and as a result, the runoff election was cancelled and Nestor Kirchner became president on May 25, 2003.

The short-term debt rollover agreement signed with the IMF on January 24, 2003 expires on August 31, 2003. Negotiations have commenced to replace the expiring agreement with a new two or three year agreement prior to September 9, 2003. Argentina is scheduled to make a payment of $3.3 billion to the IMF on this date. The IMF is expected to call for a structural reform agenda that includes the restructuring of defaulted public debts and the banking sector in order to restore financial stability in the economy. The IMF is also expected to call for tax and intergovernmental relations reform necessary to achieve sustainable public finances, as well as adjustment of utility tariffs and a plan to combat poverty and social problems. The Argentine government is expected to assert that certain structural reforms must be preceded by continued economic growth.

Bolivia. Since the mid-1980 s, Bolivia has been undergoing major economic reform, including the establishment of a free market economy and the encouragement of foreign private investment. Economic activities that had been reserved for government corporations were opened to foreign and domestic Bolivian private investments. Barriers to international trade have been reduced and tariffs lowered. A new investment law and revised codes for mining and the petroleum industry, intended to attract foreign investment, have been introduced.

Elections held during June 2002 marked the sixth consecutive democratic election held in Bolivia since 1982, representing the longest period of constitutional democratic government in the country s history. Coalitions were formed among the two leading political parties allowing Gonzalo Sanchez de Lozada to win the runoff election. Since election, President Sanchez de Lozada s government has been working to improve the economic and fiscal framework in order to facilitate new loan agreements with the IMF. After violent protests to his proposed tax increases and cuts in government spending in early 2003, President Sanchez de Lozada was forced to reorganize his government and propose a new budget for 2003. The new budget was approved and led to the IMF s approval of a one year stand-by loan agreement for $118 million in April 2003, under which $15 million was approved for disbursement in July 2003. After the recent civil disturbances and resulting financial instability, the Bolivian governments focus in 2003 will be to stabilize the economy and to establish a basis for future economic growth. In August 2003, President Sanchez de Lozada accepted the resignation of his entire cabinet and named new ministers, including members of his rival political party, in an effort to gain political support in congress for the ruling coalition.

Also in an attempt to narrow budget deficits, the government has announced new taxes on oil refiners. The oil refiners have, in turn, sued the government. While the final outcome of the newly announced tax on refiners remains unclear, the Company will receive lower prices for domestic oil sales as a result of these taxes in the short term. In the first half of 2003, the Company s Bolivian oil production accounted for less than one percent of the Company s total production from continuing operations on an equivalent barrel basis.

In 1987, the Boliviano replaced the peso at the rate of one million pesos to one Boliviano. The exchange rate is set daily by the government s exchange house, the Bolsin, which is under the supervision of the Bolivian Central Bank. Foreign exchange transactions are not subject to any controls. The exchange rate at June 30, 2003, was 7.66 Bolivianos to one U.S. dollar. The Company believes that any currency risk associated with its Bolivian operations would not have a material impact on the Company s financial position or results of operations because its gas revenues are received in U.S. dollars.

The market for gas sales in Bolivia is currently limited to exports to Brazil via the Bolivia to Brazil gas pipeline and those internal gas sales necessary to meet Bolivian industrial and consumer demand. The Company is working to increase its sales in both of these areas, and currently has capacity to deliver gas volumes substantially in excess of its contracted volumes. During the past several years, Bolivian gas reserve growth has exceeded the demand growth in Bolivia s existing markets. Therefore, the Company believes competition for markets will continue at least until new market area are established. The Pacific LNG project that would send gas volumes to the United States and a gas to liquids project for 90 MBbls per day are examples of new market concepts currently under consideration.

ITEM 4. CONTROLS AND PROCEDURES

The Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended) as of June 30, 2003. Based upon that evaluation, the Company s Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its periodic filings under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. During the period covered by this report on Form 10-Q, there were no changes in the Company s internal control over financial reporting that have materially affected or are reasonably likely to materially affect the Company s internal control over financial reporting.

PART II

OTHER INFORMATION

Item 1. Legal Proceedings

For information regarding legal proceedings, see the Company s Form 10-K for the year ended December 31, 2002.

Item 2. Changes in Securities and Use of Proceeds

not applicable

Item 3. Defaults Upon Senior Securities

not applicable

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

The Annual Meeting of Stockholders of the Company (the Annual Meeting) was held on May 13, 2003, in Tulsa, Oklahoma. At the Annual Meeting, the stockholders of the Company elected Rex D. Adams, William C. Barnes and John T. McNabb, II as Class I Directors. The stockholders also considered and approved the appointment of Ernst & Young LLP as the independent auditors of the Company for the fiscal year ending December 31, 2003.

There were present at the Annual Meeting, in person or by proxy, stockholders holding 55,882,157 shares of the Common Stock of the Company, or 87 percent of the total stock outstanding and entitled to vote at the Annual Meeting. The table below describes the results of voting at the Annual Meeting.

		Votes For	Votes Against or Withheld	Abstentions	Broker Non-Votes
1.	Election of Directors:				
	Rex D. Adams	54,587,992	1,294,165	-0-	-0-
	William C. Barnes	55,140,972	741,185	-0-	-0-
	John T. McNabb, II	54,882,895	999,262	-0-	-0-
2.	Ratification of Appointment of Ernst & Young LLP as Independent Auditors of the Company for Fiscal 2003	55,076,652	779,293	26,212	-0-

Item 5. Other Information

not applicable

Item 6. Exhibits and Reports on Form 8-K

a) Exhibits

The following documents are included as exhibits to this Form 10-Q. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, such exhibit is filed herewith.

10.1 Second Amendment to Credit Agreement dated as of May 12, 2003, among the Company, as Borrower, the Lenders party thereto, Bank of Montreal, as administrative agent, Deutsche Bank Trust Company Americas, as syndication agent, and Fleet National Bank, Societe Generale and The Bank of New York, as co-documentation agents.

31.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes - Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.

b) Reports on Form 8-K

Form 8-K dated May 7, 2003, was filed on May 8, 2003, to report under Items 7 and 9, the Company s press release dated May 7, 2003, announcing first quarter results and updated 2003 targets.

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.

VINTAGE PETROLEUM, INC.

(Registrant)

DATE: August 8, 2003

\s\ Michael F. Meimerstorf

Michael F. Meimerstorf
Vice President and Controller
(Principal Accounting Officer)

Exhibit Index

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