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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, 2005

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

(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 29, 2005
Common Stock, $0.005 Par Value	66,982,232

VINTAGE PETROLEUM, INC.

FORM 10-Q

THREE MONTHS ENDED JUNE 30, 2005

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PART I

FINANCIAL INFORMATION

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ITEM 1. FINANCIAL STATEMENTS

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except shares

and per share amounts)

(Unaudited)

ASSETS

	June 30, 2005	December 31, 2004
CURRENT ASSETS:		
Cash and cash equivalents	$ 155,804	$ 124,221
Accounts receivable -		
Oil and gas sales	127,098	107,870
Joint operations	11,854	12,479
Income taxes receivable	39,460	31,571
Deferred income taxes	22,639	15,364
Prepaids and other current assets	17,758	23,648
Total current assets	374,613	315,153
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method	2,289,876	2,163,176
Oil and gas gathering systems and plants	23,926	23,926
Other	33,313	31,932
	2,347,115	2,219,034
Less accumulated depreciation, depletion and amortization	1,009,816	942,656
Total property, plant and equipment, net	1,337,299	1,276,378
DEFERRED INCOME TAXES	10,959	13,200
OTHER ASSETS, net	50,513	40,161
TOTAL ASSETS	$ 1,773,384	$ 1,644,892

See notes to unaudited consolidated financial statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Continued)

(In thousands, except shares

and per share amounts)

(Unaudited)

LIABILITIES AND STOCKHOLDERS EQUITY

	June 30, 2005	December 31, 2004
CURRENT LIABILITIES:		
Revenue payable	$ 28,154	$ 33,740
Accounts payable - trade	55,925	50,775
Current income taxes payable	18,954	23,565
Derivative financial instruments payable	80,966	27,672
Other payables and accrued liabilities	74,401	73,748
Total current liabilities	258,400	209,500
LONG-TERM DEBT	549,952	549,949
DEFERRED INCOME TAXES	77,646	80,383
LONG-TERM LIABILITY FOR ASSET RETIREMENT OBLIGATIONS	92,008	90,707
OTHER LONG-TERM LIABILITIES	39,195	30,675
COMMITMENTS AND CONTINGENCIES (Note 5)		
STOCKHOLDERS EQUITY, per accompanying statement:		
Preferred stock, $0.01 par, 5,000,000 shares authorized, zero shares issued and outstanding		
Common stock, $0.005 par, 160,000,000 shares authorized, 67,514,467 and 66,541,984 shares issued and 66,977,600 and 66,012,252 shares outstanding, respectively	338	333
Capital in excess of par value	380,782	361,120
Retained earnings	425,352	342,707
Accumulated other comprehensive loss	(40,083)	(13,088)
	766,389	691,072
Less treasury stock, at cost, 536,867 and 529,732 shares, respectively	4,319	4,319
Less unamortized cost of non-vested stock awards	5,887	3,075
Total stockholders equity	756,183	683,678

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 1,773,384	$ 1,644,892

See notes to unaudited consolidated financial statements.

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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,	
	2005	**2004**	**2005**	**2004**
REVENUES:				
Oil, condensate and NGL sales	$ 186,089	$ 117,507	$ 351,646	$ 230,938
Gas sales	52,166	43,058	102,052	78,126
Sulfur sales	994	242	1,732	715
Gas marketing	16,124	17,462	34,702	32,234
Total revenues	255,373	178,269	490,132	342,013
COSTS AND EXPENSES:				
Production costs	43,836	34,806	87,195	70,165
Transportation and storage costs	4,300	2,741	8,529	5,061
Production and ad valorem taxes	8,332	5,519	15,216	10,825
Export taxes	16,332	6,706	29,668	12,912
Exploration costs	7,429	7,329	17,755	8,565
Gas marketing	15,124	16,480	32,666	30,551
General and administrative	16,821	16,791	34,171	34,856
Depreciation, depletion and amortization	34,353	21,881	67,750	45,967
Impairment of proved oil and gas properties				3,915
Accretion	1,792	1,629	3,539	3,247
Other operating (income) expense	1,912	1,213	2,929	(3,604)
Total costs and expenses	150,231	115,095	299,418	222,460
OPERATING INCOME	105,142	63,174	190,714	119,553
NON-OPERATING (INCOME) EXPENSE:				
Interest expense	11,600	12,674	23,155	26,695
Loss on early extinguishment of debt				9,903
Losses on derivative transactions	2,728	440	43,444	444
(Gain) loss on disposition of assets	(16)	4	(16)	(55)
Foreign currency exchange (gain) loss	1,069	(1,969)	2,335	(826)
Other non-operating income	(726)	(162)	(1,157)	(173)
Net non-operating expense	14,655	10,987	67,761	35,988
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	90,487	52,187	122,953	83,565

INCOME TAX PROVISION:				
Current	24,182	16,269	38,586	28,413
Deferred	8,587	1,216	5,467	2,089
Total income tax provision	32,769	17,485	44,053	30,502
INCOME FROM CONTINUING OPERATIONS	57,718	34,702	78,900	53,063
INCOME FROM DISCONTINUED OPERATIONS, net of income taxes		2,707	10,743	3,481
NET INCOME	$ 57,718	$ 37,409	$ 89,643	$ 56,544

See notes to unaudited consolidated financial statements.

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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,	
	2005	2004	2005	2004
BASIC INCOME PER SHARE:				
Income from continuing operations	$ 0.86	$ 0.54	$ 1.19	$ 0.83
Income from discontinued operations		0.04	0.16	0.05
Net income	$ 0.86	$ 0.58	$ 1.35	$ 0.88
DILUTED INCOME PER SHARE:				
Income from continuing operations	$ 0.86	$ 0.53	$ 1.17	$ 0.82
Income from discontinued operations		0.04	0.16	0.05
Net income	$ 0.86	$ 0.57	$ 1.33	$ 0.87
Weighted average common shares outstanding:				
Basic	66,799	64,741	66,471	64,535
Diluted	67,472	65,487	67,182	65,258

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 (LOSS)

FOR THE SIX MONTHS ENDED JUNE 30, 2005

(In thousands, except treasury shares and per share amounts)

(Unaudited)

	Common Stock			Capital In Excess of Par	Un-amortized Non-Vested Stock		Accumulated Other Compre-hensive	
	Shares	Amount	Treasury Stock	Value	Awards	Retained Earnings	Loss	Total
BALANCE AT DECEMBER 31, 2004	66,542	$ 333	$ (4,319)	$ 361,120	$ (3,075)	$ 342,707	$ (13,088)	$ 683,678
Comprehensive income (loss):								
Net income						89,643		89,643
Change in value of derivative financial instruments, net of tax							(26,995)	(26,995)
Total comprehensive income								62,648
Issuance of stock options				3				3
Exercise of stock options and tax effects	802	4		12,254				12,258
Issuance of non-vested stock	154	1		4,660	(4,661)			
Amortization of non-vested stock awards and tax effects				2,882	1,751			4,633
Forfeitures of non-vested stock (7,135 shares)				(137)	98			(39)
Vesting of stock rights	16							
Cash dividends declared ($0.105 per share)						(6,998)		(6,998)
BALANCE AT JUNE 30, 2005	67,514	$ 338	$ (4,319)	$ 380,782	$ (5,887)	$ 425,352	$ (40,083)	$ 756,183

See notes to unaudited consolidated financial statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands, except per share amounts)

(Unaudited)

	Six Months Ended June 30,	
	2005	**2004**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 89,643	$ 56,544
Adjustments to reconcile net income to cash provided by operating activities -		
Income from discontinued operations, net of tax	(10,743)	(3,481)
Depreciation, depletion and amortization	67,750	45,967
Impairment of proved oil and gas properties		3,915
Accretion	3,539	3,247
Dry hole costs, impairments of unproved oil and gas properties and other	12,010	5,684
Provision for deferred income taxes	5,467	2,089
Foreign currency exchange (gain) loss	2,335	(826)
Gain on dispositions of assets	(16)	(55)
Loss on early extinguishment of debt		9,903
Stock compensation	3,130	5,938
Non-cash derivative losses	43,444	444
Other non-cash items included in net income	613	647
Increase in receivables	(18,928)	(16,675)
Increase (decrease) in payables and accrued liabilities	(10,618)	1,744
Other working capital changes	(2,296)	4,708
Cash provided by continuing operations	185,330	119,793
Cash provided by discontinued operations		22,415
Cash provided by operating activities	185,330	142,208
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures -		
Oil and gas properties	(132,743)	(95,744)
Gathering systems and other	(1,440)	(1,430)
Payments on non-hedge derivative transactions	(12,841)	
Other	(8,266)	(913)
Cash used by investing activities - continuing operations	(155,290)	(98,087)
Cash used by investing activities - discontinued operations		(16,123)
Cash used by investing activities	(155,290)	(114,210)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	8,565	4,029
Purchase of treasury stock		(129)

Redemption of 9 3/4% Senior Subordinated Notes Due 2009		(157,313)
Advances on revolving credit facility and other borrowings	45,000	294,000
Payments on revolving credit facility and other borrowings	(45,000)	(144,900)
Dividends paid ($0.10 and $0.095 per share, respectively)	(6,626)	(5,798)
Other	106	(3,052)
Cash provided (used) by financing activities	2,045	(13,163)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(502)	634
NET INCREASE IN CASH AND CASH EQUIVALENTS	31,583	15,469
CASH AND CASH EQUIVALENTS, beginning of period	124,221	32,264
CASH AND CASH EQUIVALENTS, end of period	$ 155,804	$ 47,733

See notes to unaudited consolidated financial statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2005 and 2004

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 interest in a joint venture engaged in exploration and production activities (collectively, the Company). All significant intercompany accounts and transactions have been eliminated in consolidation. Management believes that all material adjustments (consisting of only normal recurring adjustments) necessary for a fair presentation have been made. Certain 2004 amounts have been reclassified to conform with the 2005 presentation, including reclassifications required for presentation of the discontinued operations discussed in Note 8. These reclassifications had no effect on the Company s net income 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, the 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 2004 audited financial statements and related notes included in the Company s 2004 Annual Report on Form 10-K, Item 8. Financial Statements and Supplementary Data.

2. SIGNIFICANT ACCOUNTING POLICIES

Unproved Oil and Gas Properties

Unproved oil and gas properties included in oil and gas properties in the accompanying June 30, 2005, balance sheet are as follows (in thousands):

U.S.:	
Unproved leasehold costs	$ 16,703
Unevaluated exploratory drilling	4,148
	20,851
Yemen:	
Unproved leasehold costs	2,650

Unevaluated exploratory drilling	11,186
	13,836
	$ 34,687

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Unproved leasehold costs are capitalized and reviewed periodically for impairment. Individual unproved properties are assessed for impairment on a property-by-property basis, considering factors such as future drilling and exploitation plans and lease terms. Costs related to impaired prospects are charged to expense and included in exploration costs in the accompanying statements of operations.

The Company recorded the following impairments of unproved leasehold costs (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Continuing operations	$ 23	$ 1,257	$ 1,378	$ 1,346
Discontinued operations (Canada)		1,859		3,135

Additional 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, 2005, the Company had the following exploration wells capitalized and reported as unevaluated exploratory drilling (in thousands):

Wells in progress	$ 2,694
Drilling completed - less than one year	4,774
Drilling completed - over one year	7,866
Total exploration drilling costs	$ 15,334

As of June 30, 2005, the Company had two exploration wells in Yemen on which the drilling was completed for more than one year with a total cost of approximately $7.9 million. Management believes that these wells have found sufficient reserves to justify their completion and such wells require a major capital expenditure before production can begin. Both wells are in the same prospect area. The Company has continued development and evaluation of this area during 2005. Depending on the results of such activity, the costs capitalized for the completed wells may be charged to expense during 2005. The Company had no exploration wells capitalized in areas requiring a major capital expenditure before production could begin where additional drilling efforts are not underway or firmly planned and had no exploration wells capitalized in areas not requiring a major capital expenditure where more than one year has elapsed since completion of drilling.

For the six months ended June 30, 2005, the changes in unevaluated capitalized exploratory drilling costs were as follows (in thousands):

Balance, beginning of period	$ 11,137
Additions	10,617

Charged to expense	(6,420)
Balance, end of period	$ 15,334

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On April 4, 2005, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. 19-1, *Accounting for Suspended Well Costs* (FSP 19-1). FSP 19-1 amends SFAS 19 to provide that in those situations where exploration drilling has been completed and oil and gas reserves have been found, but such reserves cannot be classified as proved when drilling is complete, the drilling costs may be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either of the criteria is not met, the well is assumed to be impaired and the costs charged to expense. Any well which has not found reserves is charged to expense. FSP 19-1 is effective for the first reporting period beginning after April 4, 2005, which will be the three months ended September 30, 2005, for the Company. Management believes that no adjustment would have been required for the three months and six months ended June 30, 2005 and 2004, from the application of FSP 19-1.

Impairments of Proved Oil and Gas Properties

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. In the first quarter of 2004, the Company recorded an impairment of $3.9 million related to one proved oil and gas property in the U.S. No impairment provision related to the Company s proved oil and gas properties was required in the second quarter of 2004 or in the first six months of 2005.

Development Seismic Costs

The Company capitalizes delineation seismic costs incurred to select development drilling locations within a productive oil and gas field as development costs. Exploration seismic costs are expensed as incurred. The Company capitalized approximately $47,000 of delineation seismic costs in the six months ended June 30, 2005.

Asset Retirement Obligations

The Company records the discounted fair value of its asset retirement obligations as a liability at the time an asset is placed in service. 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 are 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 based on proved developed reserves. The liability accretes over time with a charge to accretion expense. At June 30, 2005, there were no assets legally restricted for purposes of settling asset retirement obligations. Of the liability for asset retirement obligations balance at June 30, 2005, approximately $2.4 million is classified as current and is included in other payables and accrued liabilities in the accompanying balance sheet.

The Company recorded the following activity related to its asset retirement liability for the six months ended June 30, 2005 (in thousands):

Liability for asset retirement obligations as of January 1, 2005	$ 93,066
New obligations for wells drilled	493
Costs incurred	(2,731)
Accretion expense	3,539
Liability for asset retirement obligations as of June 30, 2005	$ 94,367

In March 2005, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies that the term conditional asset retirement obligation, as used in Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. FIN 47 requires that an entity recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. It states that uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. The Company is required to adopt FIN 47 no later than December 31, 2005. Management believes that the adoption of FIN 47 will not have a significant effect on the Company s financial position, results of operations or cash flows.

Other Payables and Accrued Liabilities

As of June 30, 2005, other payables and accrued liabilities includes $20.1 million of accrued oil and gas capital expenditures.

Derivative Financial Instruments

The Company periodically uses hedges to reduce the impact of oil and natural gas price fluctuations and generally attempts to qualify such derivatives as cash flow hedges for accounting purposes. 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. The Company defines fair value as the amount it would receive or pay to settle the derivative at period-end. 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.

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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 expected cash flows of the item being hedged. To the extent the cumulative change in the derivative exceeds the cumulative change in the expected cash flows, the excess is recognized currently in earnings as non-operating income or expense. If the cumulative change in the expected cash flows exceeds the change in fair value of the derivative, the difference is ignored. Changes in the fair value and settlements of derivative financial instruments that do not qualify, or ceased to qualify, for accounting treatment as hedges, if any, are recognized currently as non-operating income or expense. The cash flows from derivative financial instruments that do not qualify for hedge accounting are included in investing activities in the consolidated statements of cash flows.

Derivative losses included in income from continuing operations consist of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Losses under derivative instruments that did not qualify, or ceased to qualify, for hedge accounting	$	$	$ 40,962	$
Hedge ineffectiveness losses	2,728	440	2,482	444
	$ 2,728	$ 440	$ 43,444	$ 444

During the six months ended June 30, 2005, the Company realized $12.8 million of previously unrealized losses on derivative transactions.

Revenue Recognition

A portion of the Company s domestic oil sales in Argentina were previously subject to a domestic price cap agreement, relating to deliveries occurring between February 26, 2003, and April 30, 2004. Under the agreement, if the $28.50 price cap is less than the West Texas Intermediate posted price as quoted on the Platt s Crude Oil Marketwire at the time of sale, the Company is entitled to charge the oil purchasers for such difference only when the West Texas Intermediate posted price is less than the $28.50 price cap in future periods. The Company does not record any revenue under such price cap agreement until such time as the billed amounts are actually received. As of June 30, 2005, the Company had an unbilled potential recovery of approximately $7.5 million under this agreement, excluding interest. During the six months ended June 30, 2005 and 2004, the Company did not record any revenues under this agreement.

Oil inventories held in storage facilities are valued at cost, which is lower than market value. Such inventories totaled $4.8 million at June 30, 2005, and are included in prepaids and other current assets in the accompanying consolidated balance sheet.

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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, excluding fees related to the Company s discontinued operations in Canada, were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
General and administrative cost reimbursements	$ 681	$ 782	$ 1,391	$ 1,383

Stock Compensation

The Company has two fixed stock-based compensation plans which reserve shares of common stock for issuance to key employees and directors. Prior to 2003, the Company accounted for these plans under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations (collectively, APB 25). Compensation expense for restricted stock awards is recorded over the vesting periods of the awards. No stock compensation expense related to stock options granted prior to 2003 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.

Effective January 1, 2003, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (SFAS 123). The Company adopted these provisions prospectively and applied them to all employee and director awards granted, modified, or settled after January 1, 2003. Stock option awards under the Company s plans generally vest over three years, therefore, the cost related to stock compensation included in the determination of net income for the first six months of 2005 and 2004 and for the second quarters of 2005 and 2004 is less than that which would have been recognized if the fair value based method had been applied to all awards since the original effective date of SFAS 123. The following table illustrates the effect on net income and income per share if the fair value based method had been applied to all outstanding and unvested awards in each period (in thousands, except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Stock compensation expense - as reported	$ 1,624	$ 2,176	$ 3,130	$ 5,938
Stock compensation expense - pro forma	1,632	2,210	3,147	6,011
Net income - as reported	57,718	37,409	89,643	56,544
Net income - pro forma	57,713	37,387	89,631	56,498
Income per share - as reported:				
Basic	0.86	0.58	1.35	0.88

Diluted	0.86	0.57	1.33	0.87
Income per share - pro forma:				
Basic	0.86	0.58	1.35	0.88
Diluted	0.86	0.57	1.33	0.87

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The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The Company did not grant any stock options in 2004 or in the first six months of 2005.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (Revised 2004), *Share-Based Payment* (as amended by SEC Release 34-51558, SFAS 123R). SFAS 123R requires that the compensation cost relating to share-based payment transactions be recognized in the financial statements. With limited exceptions, that cost will be measured on the grant date based on the fair value of the equity or liability instruments issued. SFAS 123R also requires liability awards to be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS 123R replaces SFAS 123 and supersedes APB 25. The Company is required to adopt SFAS 123R on January 1, 2006.

Entities that use the fair-value recognition provisions under SFAS 123 are required to apply SFAS 123R using a modified version of prospective method of application. Under this method, an entity records compensation expense for all awards it grants after the date of adoption. In addition, the entity is required to record compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. Entities may elect to adopt SFAS 123R using a modified retrospective method whereby previously issued financial statements are restated based on the expense previously calculated and reported in their pro forma footnote disclosures.

As discussed above, the Company adopted the fair value recognition provisions of SFAS 123 using the prospective method and it has recognized compensation expense for all stock options granted subsequent to January 1, 2003, with no expense recognized for grants made prior to 2003. Adoption of SFAS 123R will require the Company to recognize compensation expense over the remaining service period for the unvested portion of all options granted during 2002. All options granted prior to 2003 will be fully vested by December 31, 2005.

In March 2005, the Securities and Exchange Commission (SEC) released Staff Accounting Bulletin (SAB) 107, providing additional guidance in applying the provisions of SFAS 123R. SAB 107 should be applied when adopting SFAS 123R and addresses a wide range of issues, focusing on valuation methodologies and the selection of assumptions. SAB 107 also addresses the interaction of SFAS 123R with existing SEC guidance.

Management has not yet determined the method of adoption of SFAS 123R and is presently evaluating the impact of the adoption, but management does not believe that the adoption will have a significant impact on the Company s financial position, results of operations or cash flows.

Production and Ad Valorem Taxes

Included in production and ad valorem taxes are the following items (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**

Gross production taxes	$ 6,875	$ 4,067	$ 12,295	$ 7,920
Ad valorem taxes	1,457	1,452	2,921	2,905

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Income Per Share

Basic income per common share was computed by dividing net income by the weighted average number of shares outstanding during the period. Diluted income per common share for all periods presented was computed assuming the exercise of all dilutive options, as determined by applying the treasury stock method, and assuming the vesting of all restricted stock rights.

The following table reconciles the weighted average common shares outstanding used in the calculations of basic and diluted income per share (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Weighted average common shares outstanding - Basic	66,799	64,741	66,471	64,535
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	385	568	481	561
Dilutive effect of potential common shares issuable upon the vesting of outstanding restricted stock rights	288	178	230	162
Weighted average common shares outstanding - Diluted	67,472	65,487	67,182	65,258

All of the outstanding options to purchase shares of the Company s common stock were included in the dilution calculation for the three months and six months ended June 30, 2005, because the assumed exercise of each of the options was dilutive. Certain options to purchase shares of the Company s common stock have been excluded from the dilution calculation for the three months and six months ended June 30, 2004, because the assumed exercise of these options was anti-dilutive. The following information relates to the anti-dilutive options for both the three months and the six months ended June 30, 2004:

Options excluded from dilution calculations (in thousands)	724
Range of exercise prices	$15.50 to $22.94
Weighted average exercise price	$15.82

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Comprehensive Income

Comprehensive income consists of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Net income	$ 57,718	$ 37,409	$ 89,643	$ 56,544
Foreign currency translation adjustments		(2,852)		(4,830)
Changes in value of derivative financial instruments, net of tax	6,650	(3,496)	(26,995)	(13,823)
Comprehensive income	$ 64,368	$ 31,061	$ 62,648	$ 37,891

The foreign currency translation adjustments shown above relate entirely to the translation of the financial statements of the Company s previously-owned Canadian subsidiary from its functional currency (the Canadian dollar) to the Company s reporting currency (the U.S. dollar).

The changes in the value of derivative financial instruments, net of tax, consist of the following (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Unrealized loss during the period	$ (2,385)	$ (7,773)	$ (66,905)	$ (24,675)
Reclassification adjustment for losses included in net income	13,269	1,571	22,724	1,933
	10,884	(6,202)	(44,181)	(22,742)
Income tax provision (benefit)	4,234	(2,706)	(17,186)	(8,919)
Changes in value of derivative financial instruments, net of tax	$ 6,650	$ (3,496)	$ (26,995)	$ (13,823)

The balance in accumulated other comprehensive loss at both June 30, 2005, and December 31, 2004, relates entirely to changes in the value of derivative financial instruments. Based on oil and gas prices at June 30, 2005, approximately $31.1 million of the $40.1 million balance in accumulated other comprehensive loss at June 30, 2005, will be reclassified into earnings in the next twelve months.

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Statements of Cash Flows

The Company made cash payments for interest and income taxes as follows (in thousands):

	Six Months Ended June 30,	
	2005	2004
Interest	$ 22,998	$ 26,182
Income taxes:		
U.S.	$ 6,130	$
Argentina	36,249	35,572
Canada (Discontinued operations)		1,402
	$ 42,379	$ 36,974

Approximately $123.3 million of the Company s cash at June 30, 2005, is related to the Company s foreign operations and substantially all is held in U.S. banks.

Other Recent Pronouncements

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, *Accounting Changes and Error Corrections.* Among other changes, the new standard requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to do so. The statement also provides that (1) a change in method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) correction of errors in previously issued financial statements should be termed a restatement. The new standard is effective for accounting changes and correction of errors made to the Company s financial statements beginning January 1, 2006.

3. LONG-TERM DEBT

Long-term debt at June 30, 2005, and December 31, 2004, consisted of the following (in thousands):

	June 30, 2005	December 31, 2004

Secured Debt -		
Revolving credit facility	$	$
Unsecured Debt -		
8 1/4% senior notes due 2012	350,000	350,000
7 7/8% senior subordinated notes due 2011, less unamortized discount	199,952	199,949
	$ 549,952	$ 549,949

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The Company s revolving credit facility consists of a senior secured credit facility maturing in May 2008 with availability governed by a borrowing base determination. The availability under the Company s revolving credit facility is reduced by its outstanding letters of credit. The borrowing base (currently $350 million) is based on the banks evaluation of the Company s oil and gas reserves. The amount available to be borrowed under the revolving credit facility is limited to the lesser of the borrowing base or the facility size, which is currently set at $300 million. The next borrowing base redetermination will be in November 2005. As of June 30, 2005, the Company had unused availability under its revolving credit facility of $295.6 million (considering outstanding letters of credit of approximately $4.4 million).

In February 2004, the Company advanced funds under its revolving credit facility to redeem the entire $150 million principal balance of its 9 3/4% senior subordinated notes due 2009. As a result, the Company was required to expense certain associated deferred financing costs. This $2.6 million non-cash charge and a $7.3 million cash charge for the call premium resulted in a one-time charge of approximately $9.9 million ($6.0 million net of tax).

The Company had $6.9 million of accrued interest payable related to its long-term debt at June 30, 2005, and December 31, 2004, included in other payables and accrued liabilities in the accompanying balance sheets.

4. CAPITAL STOCK

In March 2004, the Company entered into a separation agreement with a former executive under which the Company extended the period in which the former executive may exercise each outstanding vested stock option granted to him under the Company s 1990 Stock Plan to the end of the term of such option. Pursuant to the terms of the restricted stock award agreements for the shares of restricted stock granted to the Company s former executive under the Company s 1990 Stock Plan, such shares vested in full as of the date of his termination of employment. As a result, the Company recorded non-cash stock compensation expense of approximately $2.2 million in the first quarter of 2004.

The Company declared the following dividends per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Dividends declared per share	$ 0.055	$ 0.050	$ 0.105	$ 0.095

5. COMMITMENTS AND CONTINGENCIES

The Company had approximately $4.4 million in letters of credit outstanding at June 30, 2005. These letters of credit relate primarily to 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.

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The Company has entered into certain firm gas transportation and compression agreements in Bolivia whereby the Company has committed to have a third party transport and compress certain volumes of the Company s 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. The Company paid $0.9 million and $1.2 million under these agreements in the six months ended June 30, 2005 and 2004, respectively, and $0.6 million and $0.5 million under these agreements in the three months ended June 30, 2005 and 2004, respectively. Based on the current fee level, these commitments total approximately $0.6 million for the remainder of 2005, $1.3 million in 2006 and $0.3 million in each of the years 2007, 2008 and 2009.

The Company has future minimum long-term electric power purchase commitments in Argentina of $1.8 million for the remainder of 2005, $3.6 million in 2006 and $5.0 million in 2007. The Company paid $1.8 million and $1.1 million for electric power purchases under these agreements in the six months ended June 30, 2005 and 2004, respectively, and $1.0 million and $0.7 million in the three months ended June 30, 2005 and 2004, respectively.

The Company has also entered into deliver-or-pay arrangements where it has committed to deliver certain volumes of gas to third parties in Bolivia and Argentina for a specified period of time. These volumes will be sold at market prices. If the required volumes are not delivered, the Company must pay for the undelivered volumes at the then-current market price. Similar to the firm transportation and compression agreements, the Company entered into these arrangements to ensure its access to gas markets and the Company currently expects to produce sufficient volumes to satisfy all of its deliver-or-pay obligations. The volumes contracted under the agreement in Bolivia are 3.6 Bcf for the remainder of 2005, 7.0 Bcf in 2006, 6.0 Bcf in 2007, 6.9 Bcf in 2008 and 6.9 Bcf in 2009. The volumes contracted under the agreement in Argentina are 5.5 Bcf for the remainder of 2005, 6.4 Bcf in 2006, 3.6 Bcf in 2007 and 4.0 Bcf in 2008. The Company made no payments under these agreements in 2005 and 2004.

On June 17, 2005, the Company signed an agreement to purchase certain oil and gas properties in the U.S. for $10.6 million. The Company paid the seller $530,000 upon signing the agreement. This transaction was closed on July 6, 2005. Subsequent to June 30, 2005, the Company signed additional agreements to purchase certain oil and gas properties in the U.S. for approximately $52 million.

6. PRICE RISK MANAGEMENT

The Company periodically uses derivative financial instruments to reduce the impact of oil and gas price fluctuations on its operating results and cash flows and generally attempts to qualify such derivatives as hedges for accounting purposes. During the third and fourth quarter of 2004, a substantial portion of the Company s derivative financial instruments ceased to qualify for hedge accounting due to significant oil price fluctuations. The Company continued to monitor the correlation between the changes in NYMEX crude oil index prices and the changes in U.S. crude oil postings and, as of March 1, 2005, the Company determined that the correlation indicated that its existing oil price swap agreements would again be highly effective in achieving offsetting changes in the cash flows of the physical transactions. Accordingly, as of March 1, 2005, the Company redesignated all of its oil price swap contracts as cash flow hedges and resumed hedge accounting for these contracts. As of March 1, 2005, and through June 30, 2005, all of the Company s derivative financial instruments qualified as hedges for accounting purposes.

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During the first six months of 2004, the Company participated in oil price swap agreements covering 2.9 million barrels of its oil production at a weighted average NYMEX reference price of $29.89 per barrel and gas price swap agreements covering 1.2 million MMBtu of its gas production at a weighted average NYMEX reference price of $5.85 per MMBtu. During the first six months of 2005, the Company participated in oil price swap agreements covering 2.5 million barrels of its oil production at a weighted average NYMEX reference price of $37.13 per barrel, gas price swap agreements covering 2.3 million MMBtu of its gas production at a weighted average NYMEX reference price of $6.40 per MMBtu and gas price collar agreements covering 5.4 million MMBtu of its gas production with NYMEX floor reference prices of $6.00 per MMBtu and NYMEX cap reference prices ranging from $6.80 to $9.21 per MMBtu. In conjunction with each of the 2005 and 2004 U.S. gas price swap and collar agreements, the Company entered into basis swap agreements covering identical periods of time and volumes. 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 not entered into any new oil or gas price swap agreements or collars since December 31, 2004. The Company continues to monitor oil and gas prices and may enter into additional derivative transactions in the future.

The Company records the fair value of its commodity swap agreements as a current or long-term asset or liability based on the period in which the forecasted transaction will occur. The fair value of the derivative financial instrument obligation at June 30, 2005, consisted of a current liability of $81.0 million and an other long-term liability of $28.2 million. Fair value was determined using actively quoted market prices.

7. INCOME TAXES

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

	Six Months Ended June 30,	
	2005	**2004**
U.S. federal statutory income tax rate	35.0%	35.0%
U.S. state income tax (net of federal tax benefit)	0.6	0.1
U.S. permanent differences	(2.9)	(2.0)
Foreign operations	3.1	3.4
	35.8%	36.5%

The impact of foreign operations is primarily the result of lower tax depreciation, depletion and amortization in Argentina due to the inability to utilize inflation accounting for tax purposes. 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. At December 31, 2004, income considered to be permanently reinvested in certain foreign subsidiaries totaled approximately $425 million. The Company has paid or accrued foreign income taxes of approximately $230 million related to this income which may be available as a credit against U.S. federal income taxes on such income, if distributed. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed because the amount of foreign taxes eligible for credit against U.S. federal income taxes on any such distribution will be determined based on facts and circumstances at the time of any actual distribution.

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During the first quarter of 2005, the Company reversed approximately $13.1 million of contingent liabilities related to U.S. federal and state income taxes. These contingent tax liabilities related to tax benefits resulting from certain filing positions taken for which the Company initially concluded, for financial reporting purposes, that, under GAAP, it was not appropriate to recognize these benefits until the filing positions taken were sustained under a tax audit. During the first quarter of 2005, federal and state auditors completed audits of the Company s tax returns for the periods involved, with no adjustments related to these filing positions required. Therefore, the Company concluded that it was now appropriate to recognize these tax benefits for financial reporting purposes. Approximately $10.7 million of these tax benefits were related to previously-discontinued operations and are reflected as income from discontinued operations in the accompanying consolidated statement of operations for the six months ended June 30, 2005. The remaining $2.4 million is included as a reduction to the continuing operations deferred income tax provision in the accompanying consolidated statement of operations for the six months ended June 30, 2005.

The American Jobs Creation Act of 2004 (the Jobs Act) introduced a special one-time dividends-received deduction on the repatriation of certain foreign earnings to the U.S., provided certain conditions are met. If certain conditions are met, a 5.25 percent effective income tax rate would apply to eligible repatriations of certain foreign earnings. The Company is currently evaluating these provisions under the Jobs Act and is also awaiting interpretive guidance relating to these regulations from either Congress or the Treasury Department. At the current date, the Company has not determined that it will repatriate any unremitted foreign earnings under the special one-time repatriation provisions of the Jobs Act. However, the Company continues to evaluate the special one-time repatriation provisions of the Jobs Act and that evaluation could result in the Company repatriating certain unremitted foreign earnings. The amount of unremitted foreign earnings that the Company is evaluating for repatriation, including projected 2005 earnings, ranges from zero to $500 million. The Company expects to complete its evaluation of the amount of repatriation, if any, during 2005. If the Company was to repatriate certain unremitted foreign earnings under the special one-time repatriation provisions of the Jobs Act in the range noted in the preceding sentence, the income tax effects of such repatriation could range from zero to approximately $26 million.

8. DISCONTINUED OPERATIONS

On November 30, 2004, the Company completed the sale of its operations in Canada. The Company received $274.7 million in cash and recorded a gain of $167.8 million ($198.5 million including income tax benefit).

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 Canada are accounted for as discontinued operations in the accompanying consolidated financial statements.

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

	Three Months Ended June 30, 2004	Six Months Ended June 30, 2004
Revenues	$ 25,711	$ 50,746
Income from discontinued operations	$ 2,672	$ 3,799
Income tax provision (benefit)	(35)	318

Income from discontinued operations, net of tax	$ 2,707	$ 3,481

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As discussed in Note 7, in the first quarter of 2005, the Company reversed approximately $10.7 million of contingent U.S. federal and state income tax liabilities related to its previously-discontinued operations in Trinidad.

9. 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 crude oil, condensate, natural gas liquids and natural gas. The gas marketing segment generates a margin through the purchase and resale of both Company-produced and third party-produced gas volumes. The Company evaluates the performance of its operating segments based on operating income.

Intersegment sales are priced in accordance with terms of existing contracts and current market conditions. Capital investments include expensed exploratory costs. Amounts below the operating income line on the statements of operations are not allocated to segments. General and administrative expense and stock compensation are included in the corporate segment, except for certain operating expenses related to oil and gas producing activities, which are allocated to each exploration and production segment.

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Operations in the gas marketing segment are in the U.S. The Company operates in the oil and gas exploration and production industry in the U.S., Argentina, Bolivia, Yemen and Bulgaria. The financial information related to the Company s discontinued operations in Canada has been excluded in all periods presented (see Note 8). Summarized financial information for the Company s reportable segments for the six months and three months ended June 30, 2005 and 2004, is shown in the following tables (in thousands):

	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
Six Months Ended 6/30/05					
External segment revenues	$ 212,963	$ 203,069	$ 5,248	$ 34,150	$
Intersegment revenues					
Depreciation, depletion and amortization expense	32,237	29,027	1,239	4,287	
Operating income (loss)	106,991	93,903	1,698	17,362	(215)
Total assets	689,120	687,825	112,903	82,952	1,995
Capital investments	63,053	62,914		17,801	193
Long-lived assets	584,509	601,161	87,455	58,567	

	Gas Marketing	Corporate	Total
Six Months Ended 6/30/05			
External segment revenues	$ 34,702	$	$ 490,132
Intersegment revenues	1,737		1,737
Depreciation, depletion and amortization expense		960	67,750
Operating income (loss)	2,036	(31,061)	190,714
Total assets	18,337	180,252	1,773,384
Capital investments		1,440	145,401
Long-lived assets		5,607	1,337,299

	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
Six Months Ended 6/30/04					
External segment revenues	$ 154,504	$ 146,819	$ 6,727	$ 1,729	$
Intersegment revenues					
Depreciation, depletion and amortization expense	22,234	21,003	1,460	222	
Operating income (loss)	65,314	80,363	2,894	763	(4,863)
Total assets	509,565	563,211	112,274	26,027	1,925
Capital investments	52,063	42,562		7,139	4,016
Long-lived assets	468,009	512,325	89,973	29,989	

	Gas Marketing	Corporate	Total
Six Months Ended 6/30/04			
External segment revenues	$ 32,234	$	$ 342,013

Intersegment revenues	926		926
Depreciation, depletion and amortization expense		1,048	45,967
Operating income (loss)	1,683	(26,601)	119,553
Total assets	17,814	72,868	1,303,684
Capital investments		1,049	106,829
Long-lived assets		5,185	1,105,481

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	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
Three Months Ended 6/30/05					
External segment revenues	$ 114,911	$ 104,227	$ 2,665	$ 17,446	$
Intersegment revenues					
Depreciation, depletion and amortization expense	16,319	14,575	610	2,316	
Operating income (loss)	60,939	49,098	757	8,673	(35)
Total assets	689,120	687,825	112,903	82,952	1,995
Capital investments	34,314	33,627		11,703	30
Long-lived assets	584,509	601,161	87,455	58,567	

	Gas Marketing	Corporate	Total
Three Months Ended 6/30/05			
External segment revenues	$ 16,124	$	$ 255,373
Intersegment revenues	1,018		1,018
Depreciation, depletion and amortization expense		533	34,353
Operating income (loss)	1,000	(15,290)	105,142
Total assets	18,337	180,252	1,773,384
Capital investments		931	80,605
Long-lived assets		5,607	1,337,299

	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
Three Months Ended 6/30/04					
External segment revenues	$ 80,624	$ 75,143	$ 3,311	$ 1,729	$
Intersegment revenues					
Depreciation, depletion and amortization expense	11,570	8,899	744	222	
Operating income (loss)	37,188	42,678	1,376	1,027	(4,680)
Total assets	509,565	563,211	112,274	26,027	1,925
Capital investments	30,066	21,251		4,572	3,688
Long-lived assets	468,009	512,325	89,973	29,989	

	Gas Marketing	Corporate	Total
Three Months Ended 6/30/04			
External segment revenues	$ 17,462	$	$ 178,269
Intersegment revenues	545		545
Depreciation, depletion and amortization expense		446	21,881
Operating income (loss)	981	(15,396)	63,174
Total assets	17,814	72,868	1,303,684
Capital investments		375	59,952
Long-lived assets		5,185	1,105,481

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

We are an independent energy company with operations primarily in the exploration and production and gas marketing segments of the oil and gas industry. We have operations or exploration activities in the U.S., South America, Yemen, and Bulgaria. We are focused on the acquisition of oil and gas properties which contain the potential for increased value through exploitation and exploration. In addition, we are focused on continuing to build an inventory of exploration prospects in the U.S. that may impact production in the near term as well as high potential frontier prospects that may impact production in the longer term.

During 2004 and 2005, we have been focused on our core objectives of acquisitions, exploitation and exploration. We completed two acquisitions of producing properties in 2004, one in September 2004 in Argentina at a total cost of $34.9 million and one in the U.S. in December 2004 at a total cost of $77.2 million. In the first six months of 2005, we spent an additional $9.1 million on acquisitions, primarily in the U.S., and subsequent to June 30, 2005, we made additional U.S. acquisitions for $9.8 million and we have signed additional agreements to purchase certain oil and gas properties in the U.S. for approximately $52 million. This increased focus on our core objectives has resulted in a significant improvement in our production levels and our operating results. It has also allowed us to significantly increase our capital expenditures in 2004 and 2005 compared to previous years. We incurred $144.0 million of oil and gas capital expenditures in the first six months of 2005 and we plan to spend approximately $285 million in 2005, exclusive of acquisitions. We expect to have sufficient internally generated cash flows to fund our non-acquisition capital expenditures. In the event we successfully secure acquisitions of oil and gas properties, we will seek appropriate levels of oil and gas price risk management and debt and equity capital in order to maintain our financial flexibility.

We reported net income of $57.7 million in the second quarter of 2005, representing a 66 percent increase over income from continuing operations of $34.7 million in the second quarter of 2004. Net income for the second quarter of 2004 was $37.4 million, including income from discontinued operations of $2.7 million. Our net income for the six months ended June 30, 2005, was $89.6 million, compared to net income of $56.5 million for the six months ended June 30, 2004. Net income for the first six months of 2005 included $10.7 million of income from discontinued operations versus $3.5 million of income from discontinued operations in the first six months of 2004. Income from continuing operations for the first six months of 2005 was significantly impacted by $41.0 million of losses under derivative instruments that did not qualify, or ceased to qualify, for hedge accounting. These losses resulted primarily from substantial increases in oil prices during January and February 2005, when most of our oil price swap agreements were accounted for under mark-to-market accounting. As of June 30, 2005, $12.8 million of these losses had been realized and $28.2 million remained unrealized. Net income for the first six months of 2005 was reduced by $17.2 million ($28.2 million before taxes) related to these unrealized losses. As these derivative instruments settle in future periods, we will report higher oil revenues in those future periods than would have been reported had the unrealized losses not been recognized in the first six months of 2005. As of March 1, 2005, we redesignated all of our oil price swap agreements as cash flow hedges and therefore we were allowed to cease mark-to-market accounting for these derivative financial instruments.

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Production from continuing operations for the second quarter of 2005 of 6.9 MMBOE was 17 percent greater than the 5.9 MMBOE of production from continuing operations for the second quarter of 2004. Similarly, production from continuing operations for the six months ended June 30, 2005, of 13.7 MMBOE was 18 percent greater than the 11.5 MMBOE of production from continuing operations for the six months ended June 30, 2004. These increases resulted from the acquisitions discussed above, the results of our successful exploration activities in Yemen and the results of our successful exploitation and exploration activities in the U.S. and Argentina. Our U.S. production for the three months and six months ended June 30, 2005, was reduced by an estimated 47 MBOE and 279 MBOE, respectively, as a result of heavy rains and mudslides in Ventura County, California, which required us to shut in certain wells. These shut-in wells have now been returned to production. Our Argentina production for the three months and six months ended June 30, 2004, was negatively impacted by a labor strike, which reduced production by an estimated 228 MBOE and 415 MBOE, respectively.

As a result of the 18 percent increase in production on a BOE basis discussed above and higher oil and gas prices, our cash provided by continuing operations for the first six months of 2005 was $185.3 million, which was 55 percent higher than the first six months of 2004. The increases in cash flow from increased production and higher prices were slightly offset by higher cash operating expenses.

Our future financial results depend on a number of factors, including, in particular, oil and gas prices, our ability to find or acquire oil and gas reserves, access to capital, our ability to control costs and both domestic and foreign regulatory developments. Commodity prices are impacted by many factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Oil and gas prices are affected by changes in market demands, overall economic activity, political events, weather, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future oil and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital programs, production volumes, future revenues or our ability to acquire oil and gas properties. In addition to production volumes and commodity prices, acquiring, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success.

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Results of Operations

Our results of operations have been significantly affected by our success in acquiring oil and gas properties and our ability to maintain or increase production through our exploitation and exploration activities. Acquisitions of producing oil and gas properties in the U.S. and Argentina during late 2004 and the disposition of our Canadian operations in November 2004 affect the comparability of operating data for the periods presented in the tables below. Fluctuations in oil and gas prices have also significantly affected our results. The following table reflects our oil and gas production and our average oil and gas sales prices for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Production:				
Oil (MBbls) -				
U.S. (a)	1,727	1,532	3,191	3,045
Argentina (b)(c)	3,017	2,434	6,101	4,875
Bolivia (b)	15	21	30	41
Yemen (b)	342	59	703	59
Continuing operations	5,101	4,046	10,025	8,020
Canada		215		450
Total	5,101	4,261	10,025	8,470
Gas (MMcf) -				
U.S. (a)	7,141	7,125	14,824	13,365
Argentina (c)	2,228	2,147	4,381	4,179
Bolivia	1,236	1,829	2,567	3,548
Continuing operations	10,605	11,101	21,772	21,092
Canada		3,868		7,806
Total	10,605	14,969	21,772	28,898
MBOE from continuing operations	6,869	5,896	13,654	11,535
Total MBOE	6,869	6,756	13,654	13,286

(a) U.S. production for the three months and six months ended June 30, 2005, is estimated to have been reduced as a result of mudslides in Ventura County, California by 36 MBbls of oil and 66 MMcf of gas, or 47 MBOE, and 228 MBbls of oil and 304 MMcf of gas, or 279 MBOE, respectively.

(b) Oil production (in MBbls) before the impact of changes in inventories:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Argentina	3,032	2,455	5,856	4,931
Bolivia	14	22	27	43
Yemen	391	108	735	109

(c)

Argentina production for the three months and six months ended June 30, 2004, is estimated to have been reduced as the result of a labor strike by 200 MBbls of oil and 165 MMcf of gas, or 228 MBOE, and 365 MBbls of oil and 300 MMcf of gas, or 415 MBOE, respectively.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Average Sales Price (including impact of hedges):				
Oil (per Bbl) -				
U.S. (a)	$ 38.36	$ 27.12	$ 36.82	$ 27.53
Argentina	33.83	30.29	32.67	29.62
Bolivia	22.62	24.67	22.87	24.26
Yemen	51.02	29.15	48.57	29.15
Continuing operations (a)	36.48	29.04	35.08	28.80
Canada		28.80		28.30
Gas (per Mcf) -				
U.S.	$ 6.68	$ 5.45	$ 6.32	$ 5.24
Argentina	0.96	0.66	0.86	0.58
Bolivia	1.87	1.54	1.78	1.62
Continuing operations	4.92	3.88	4.69	3.70
Canada		5.02		4.85
Average Sales Price (excluding impact of hedges):				
Oil (per Bbl) -				
U.S.	$ 45.55	$ 34.54	$ 44.07	$ 33.54
Argentina	33.83	30.29	32.67	29.62
Bolivia	22.62	24.67	22.87	24.26
Yemen	51.02	29.15	48.57	29.15
Continuing operations	38.91	31.85	37.39	31.08
Canada		33.94		32.29
Gas (per Mcf) -				
U.S.	$ 6.80	$ 5.52	$ 6.29	$ 5.28
Argentina	0.96	0.66	0.86	0.58
Bolivia	1.87	1.54	1.78	1.62
Continuing operations	5.00	3.92	4.67	3.72
Canada		5.02		4.85

(a) The average oil sales price per barrel for the U.S. does not reflect realized losses of $4.92 and $4.02 per barrel for the three months and six months ended June 30, 2005, respectively, which relate to settlements on economic hedges. The average oil sales price per barrel for continuing operations does not reflect realized losses of $1.67 and $1.28 per barrel for the three months and six months ended June 30, 2005, respectively, which relate to settlements on economic hedge. These losses have been reflected in non-operating expense. Economic hedges are derivative financial instruments, intended to hedge a specific exposure, that do not qualify or ceased to qualify for hedge accounting under SFAS 133.

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Oil Prices

Average U.S. oil prices we receive generally fluctuate with changes in the NYMEX reference price for oil. Our oil production in Argentina is sold primarily 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. Our Yemen oil production is sold at Dated Brent prices as quoted in Platt s Crude Oil Marketwire less a specified differential. We experienced a 26 percent increase in our average oil price from continuing operations, including the impact of hedging activities (22 percent excluding the impact of hedging activities), during the second quarter of 2005 compared to the second quarter of 2004. In the first six months of 2005, we experienced a 22 percent increase in our average oil price from continuing operations, including the impact of hedging activities (20 percent excluding the impact of hedging activities), compared to the first six months of 2004.

During late 2004 and continuing in the first six months of 2005, the NYMEX reference price for crude oil was at or above $45.00 per barrel and our contract differentials on our California and Argentina properties increased, thus lowering our average realized oil prices as a percent of NYMEX. During the second quarter and early in the third quarter of 2005, we experienced an improvement in these contract differentials, however, they currently remain above historical levels. If future NYMEX reference prices stay at or above this level, our realized price as a percentage of NYMEX may be lower than our previous historical relationships.

Our Argentina oil production is subject to an export tax. This tax is applied on the sales value after the tax, thus, the effective tax rate is less than the stated rate. The export tax rate was 20 percent in the first quarter of 2004. In May 2004, the Argentine government increased the export tax from 20 percent to 25 percent. In August 2004, the Argentine government further increased the export tax rates for oil exports. The export tax now escalates from 25 percent (which results in a 20 percent effective rate) to a maximum rate of 45 percent (which results in a 31 percent effective rate) of the realized value for exported barrels as West Texas Intermediate posted prices per Bbl increase from less than $32.00 to $45.00 and above. The export tax is deducted for income tax purposes but is not deducted in the calculation of royalty payments. The export tax expires in February 2007. Given the number of governmental changes during 2004 affecting the realized price we receive for our oil sales, no specific predictions can be made about the future of oil prices in Argentina; however, in the short term, we expect Argentine oil realizations to be less than oil realizations in the U.S. Export oil sales are valued and paid in U.S. dollars. Domestic Argentine oil sales, while valued in U.S. dollars, are paid in equivalent pesos.

We currently export approximately 35 percent of our Argentine oil production. The U.S. dollar equivalent value for domestic Argentine oil sales (paid in pesos) has generally moved toward 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 Argentine income tax savings related to deducting the impact of the export tax.

On January 2, 2003, at the Argentine government s request, crude oil producers and refiners agreed to limit amounts payable for certain 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 West Texas Intermediate posted price and the maximum price would be payable once the West Texas Intermediate posted price fell below the maximum. The debt payable under the original agreement accrues interest at eight percent. The total debt will be collected by invoicing future deliveries at $28.50 per Bbl after the West Texas Intermediate posted price falls below the maximum price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for 10 consecutive days, which occurred on February 24, 2003.

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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. This agreement, which was extended several times under similar terms, expired on April 30, 2004. At June 30, 2005, the accumulated balance of amounts which we may charge to domestic oil purchasers in Argentina, if the West Texas Intermediate posted price decreases below the established maximum price in the future, was approximately $7.5 million, excluding interest. We do not have the right to invoice for such amounts until such time as the West Texas Intermediate posted price declines below the established price cap of $28.50. Accordingly, we have adopted a revenue recognition accounting policy for this potential revenue in which we will record such revenue only upon the receipt of payment for this additional billing due to the uncertainty of recovery of such amounts and the timing thereof. During 2004 and 2005, we did not record any revenue under this agreement.

To the extent that derivative financial instruments qualify for accounting treatment as cash flow hedges, we record the cash settlements as an adjustment to oil and gas sales. During the first six months of 2004, we participated in oil price swap agreements covering 2.9 million barrels of our oil production at a weighted average NYMEX reference price of $29.89 per barrel and during the first six months of 2005, we participated in oil price swap agreements covering 2.5 million barrels of our oil production at a weighted average NYMEX reference price of $37.13 per barrel. We accounted for all of the oil price swaps during the first six months of 2004 as cash flow hedges and we accounted for 2.4 million barrels for the first six months of 2005 oil price swaps as cash flow hedges. The impact on our average sales prices of the cash settlements under oil price swaps accounted for as cash flow hedges are reflected in the preceding tables.

Gas Prices

Average U.S. gas prices we receive generally fluctuate with changes in spot market prices, which may vary significantly by region. Most of our Bolivian gas production is sold at average gas prices tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. Our Argentine gas is sold under spot contracts of varying lengths and we are paid in pesos. This has 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. Market prices for gas in Argentina have historically been significantly less than developed countries, such as the U.S. This is primarily due to limited gas markets and gas infrastructure in the region whose developed supplies have been sufficient to meet both internal demand and allow for exports to Chile. Our total average gas price from continuing operations for the first six months of 2005 was 27 percent higher than the same period in 2004, including the impact of hedging activities (26 percent higher excluding hedging activities). Our total average gas price for the second quarter of 2005, including the impact of hedging activities was 27 percent higher (28 percent higher excluding hedging activities) than the same period of 2004.

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During the first six months of 2004, we participated in gas price swap agreements covering 1.2 million MMBtu of our gas production at a weighted average NYMEX reference price of $5.85 per MMBtu. During the first six months of 2005, we participated in gas price swap agreements covering 2.3 million MMBtu of our gas production at a weighted average NYMEX reference price of $6.40 per MMBtu and gas price collar agreements covering 5.4 million MMBtu of our gas production with NYMEX floor reference prices of $6.00 per MMBtu and NYMEX cap reference prices ranging from $6.80 to $9.21 per MMBtu. In conjunction with each of our 2005 U.S. gas price swap and collar agreements, we entered into basis swap agreements covering identical periods of time and volumes. 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 we have received. All of these gas price swaps were accounted for as cash flow hedges. The impacts of the cash settlements under these cash flow hedges on our average gas prices are reflected in the preceding tables.

Future Period Price Risk Management

We produce, purchase and sell crude oil, natural gas, condensate, natural gas liquids and sulfur. As a result, our financial results can be significantly impacted as these commodity prices fluctuate widely in response to changing market forces. Relatively modest changes in either oil or gas prices significantly impact our results of operations and cash flows. However, the impact of changes in the market prices for oil and gas on our average realized prices may be reduced from time to time based on the level of our hedging activities. Based on oil production from continuing operations for the six months of 2005, a change in the average oil price we realize, before hedges, of $1.00 per Bbl would result in a change in net income and revenues less production and export taxes on an annual basis of approximately $11.9 million and $18.5 million, respectively. A 10 cent per Mcf change in the average gas price we realize, before hedges, would result in a change in net income and revenues less production taxes on an annual basis of approximately $2.7 million and $4.3 million, respectively, based on gas production for the first six months of 2005.

We have previously engaged in oil and gas derivative transactions and we intend to continue to consider various derivative transactions to realize commodity prices which we consider favorable. The counterparties to all of our current derivative transactions are commercial or investment banks.

The following table reflects the volume of our future oil production under price swap arrangements and the corresponding weighted average NYMEX reference prices by quarter:

Quarter Ending	Barrels	NYMEX Reference Price Per Barrel
September 30, 2005	1,269,600	$ 35.57
December 31, 2005	1,269,600	34.88
March 31, 2006	427,500	37.39
June 30, 2006	432,250	36.80
September 30, 2006	437,000	36.32
December 31, 2006	437,000	35.93
March 31, 2007	189,000	34.26
June 30, 2007	63,700	39.66
September 30, 2007	64,400	39.38
December 31, 2007	64,400	39.10

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The following table reflects the volume of our future gas production under price swap arrangements and the corresponding weighted average NYMEX reference prices by quarter:

Quarter Ending	MMBtu	NYMEX Reference Price Per MMBtu
September 30, 2005	1,186,800	$ 6.17
December 31, 2005	1,186,800	6.37
March 31, 2006	243,000	6.47
June 30, 2006	245,700	6.47
September 30, 2006	248,400	6.47
December 31, 2006	248,400	6.47
March 31, 2007	225,000	6.00
June 30, 2007	227,500	6.00
September 30, 2007	230,000	6.00
December 31, 2007	230,000	6.00

We have also entered into various gas price collar arrangements for 2005. The following table reflects the MMBtu covered by these gas price collars and the corresponding NYMEX floor and cap reference prices:

Remaining 2005 Gas Production (MMBtu)	NYMEX Floor Reference Price Per MMBtu	NYMEX Cap Reference Price Per MMBtu
920,000	$ 6.00	$ 6.80
1,840,000	6.00	8.02
920,000	6.00	8.73
1,840,000	6.00	9.21

We also have entered into basis swap agreements for all of our gas production covered by the price swaps and price collars. 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 we have received.

At June 30, 2005, we would have been required to pay $109.2 million to terminate our swaps and price collars then in place. The following table summarizes the change in fair value for all of our derivative financial instruments for the three months and six months ended June 30, 2005, and 2004 (in thousands):

	Three Months Ended June 30,	Six Months Ended June 30,

	2005	2004	2005	2004
Fair value of contracts at beginning of period	$ (125,878)	$ (22,595)	$ (34,446)	$ (7,551)
Net realized losses on contracts settled	21,761	12,976	35,565	20,582
Net decrease in fair value of all open contracts	(5,113)	(19,805)	(110,349)	(42,455)
Fair value of contracts at end of period	$ (109,230)	$ (29,424)	$ (109,230)	$ (29,424)

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Beginning in September 2004 and continuing through February 2005, the differential between the NYMEX index price for crude oil and West Coast and other U.S. crude oil postings widened. Although the NYMEX crude oil index prices increased, many crude oil postings under which we sell our oil did not increase at the same rate. This market fluctuation caused us to conclude that most of our crude oil hedges were no longer highly effective in achieving offsetting changes in the cash flows of the physical transactions. In accordance with SFAS 133, we discontinued hedge accounting for these contracts beginning in September and recorded the changes in the fair value of these contracts as a charge to losses on derivative transactions. As of March 1, 2005, we determined that the correlation indicated that our existing oil price swap agreements will again be highly effective in achieving offsetting changes in the cash flows of the physical transactions and, accordingly, we redesignated all of our oil price swap contracts as cash flow hedges and resumed hedge accounting for these contracts as of March 1, 2005.

During the period from September 2004 through February 2005, we recorded a total of $60.7 million of unrealized losses under derivative instruments that did not qualify, or ceased to qualify for hedge accounting as losses on derivative transactions. As of June 30, 2005, we have now realized $22.8 million of these previously recorded losses, $12.8 million of which was realized in the first six months of 2005. However, since the losses were previously recorded as an expense, the realization of the $22.8 million of losses resulted in higher reported oil sales than would have been reported if we had not recorded these losses in previous periods. Accordingly, as we realize the remaining $37.9 million of previously recorded losses, we will report higher oil sales than would be reported had these charges not been recorded in previous periods, as follows (in thousands):

Quarter Ending	
September 30, 2005	$ 8,745
December 31, 2005	8,455
March 31, 2006	4,786
June 30, 2006	4,593
September 30, 2006	4,384
December 31, 2006	4,151
March 31, 2007	1,948
June 30, 2007	300
September 30, 2007	288
December 31, 2007	273

Period to Period Comparison

On November 30, 2004, we sold all of our Canadian operations. We received $274.7 million in cash and recorded a gain of $167.8 million ($198.5 million after income taxes) in the fourth quarter of 2004. In accordance with the rules established by Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, our operations in Canada are accounted for as discontinued operations in our consolidated financial statements. ***Accordingly, the revenues and operating expenses discussed on the following pages exclude the results related to our operations in Canada for all periods.***

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	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Variance	
Revenues:				
Oil, condensate and NGL sales	$ 186,089	$ 117,507	$ 68,582	58%
Gas sales	52,166	43,058	9,108	21%
Sulfur sales	994	242	752	311%
Gas marketing	16,124	17,462	(1,338)	-8%
Total revenues	$ 255,373	$ 178,269	$ 77,104	43%
Production:				
Oil, condensate and NGL volumes (MBbls)	5,101	4,046	1,055	26%
Gas volumes (MMcf)	10,605	11,101	(496)	-4%
Total production (MBOE)	6,869	5,896	973	17%
Average sales price (including impact of hedges):				
Oil, condensate and NGL (per Bbl)	$ 36.48	$ 29.04	$ 7.44	26%
Gas (per Mcf)	4.92	3.88	1.04	27%

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	Variance	
Revenues:				
Oil, condensate and NGL sales	$ 351,646	$ 230,938	$ 120,708	52%
Gas sales	102,052	78,126	23,926	31%
Sulfur sales	1,732	715	1,017	142%
Gas marketing	34,702	32,234	2,468	8%
Total revenues	$ 490,132	$ 342,013	$ 148,119	43%
Production:				
Oil, condensate and NGL volumes (MBbls)	10,025	8,020	2,005	25%
Gas volumes (MMcf)	21,772	21,092	680	3%
Total production (MBOE)	13,654	11,535	2,119	18%
Average sales price (including impact of hedges):				
Oil, condensate and NGL (per Bbl)	$ 35.08	$ 28.80	$ 6.28	22%
Gas (per Mcf)	4.69	3.70	0.99	27%

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Oil, condensate and NGL sales. The 26 percent increase in production from the second quarter of 2004 to the second quarter of 2005 resulted in a $38.5 million increase in our oil, condensate and NGL sales between the same periods. The remaining $30.1 million increase in oil, condensate and NGL sales from the second quarter of 2004 to the second quarter of 2005 was the result of a 26 percent increase in our average oil price between the same periods.

Similarly, oil, condensate and NGL sales increased by $70.3 million from the first six months of 2004 to the first six months of 2005 as a result of the 25 percent increase in production between the same periods. The remaining $50.4 million increase in oil, condensate and NGL sales from the first six months of 2004 to the first six months of 2005 was the result of a 22 percent increase in our average oil price between the same periods.

Our oil production in Argentina for the second quarter of 2005 averaged 33,157 BOPD, representing a 24 percent increase over the 26,746 BOPD for the second quarter of 2004. Oil production from Argentina for the first six months of 2005 averaged 33,706 BOPD compared to 26,787 BOPD for the first six months of 2004, which is a 26 percent increase between these periods. The increases were the results of additional production resulting from our drilling and workover programs and our acquisition of producing properties in the San Jorge basin in September 2004. In addition, both the second quarter of 2004 and the first six months of 2004 were negatively impacted by a labor strike which reduced reported production for these periods by an estimated 200 MBbls and 365 MBbls, respectively. There were no similar disruptions in 2005.

Oil production from our An Nagyah field in Yemen began making a contribution in the second quarter of 2004. Our Yemen oil production was 59 MBbls for both the second quarter and first six months of 2004. This compares to our Yemen oil production of 342 MBbls for the second quarter of 2005 and 703 MBbls for the first six months of 2005. Through June 30, 2005, all of our An Nagyah field production was transported by truck to a nearby facility for processing and transporting to an export terminal. We have completed an 18-mile pipeline to the processing facility and it became operational in early July 2005. We anticipate the An Nagyah production to increase to 10,000 gross BOPD (5,200 net) by the middle of the third quarter of 2005.

Our U.S. oil production increased by 13 percent from 16,839 BOPD in the second quarter of 2004 to 18,967 BOPD in the second quarter of 2005 and increased by five percent from 16,730 BOPD in the first six months of 2004 to 17,628 BOPD in the first six months of 2005. These increases resulted from our December 2004 acquisition of producing properties in Alabama and from our 2005 exploitation successes. Partially offsetting these increases, we estimate that our U.S. oil production for the three months and six months ended June 30, 2005, was reduced by 36 MBbls and 228 MBBls, respectively, as a result of heavy rains and mudslides in Ventura County, California, which required us to shut in certain wells. These shut-in wells have now been returned to production.

Gas sales. The increase in gas sales from the second quarter of 2004 to the second quarter of 2005 was the result of the 27 percent increase in our average gas price between the same periods. The $11.5 million increase in gas sales from the price increase was reduced by $2.4 million resulting from a four percent decline in our gas production from the second quarter of 2004 to the second quarter of 2005.

Our gas sales increased by $23.9 million from the first six months of 2004 to the first six months of 2005. A 27 percent increase in prices between the same period, accounted for $20.7 million of this increase. The remaining $3.2 million of the increase was the result of a three percent increase in our gas production from the first six months of 2004 to the first six months of 2005.

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Although gas production in the U.S. and Argentina increased slightly between the second quarter of 2004 and the second quarter of 2005, the decline in our gas production in Bolivia led to the overall four percent decrease between the same periods. Similarly, for the first six months of 2005 compared to the first six months of 2004, an 11 percent increase in our U.S. gas production and a five percent increase in our Argentine gas production were offset by a 28 percent decline in our Bolivian gas volumes, resulting in only a three percent increase in gas production on a worldwide basis between these periods.

Our successful exploitation program in the U.S. and our December 2004 acquisition of producing properties in Alabama again were the primary reason for the U.S. production increase. Offsetting these increases, we estimate that our U.S. gas production was reduced by 66 MMcf for the second quarter of 2005 and 304 MMcf for the first six months of 2005 as a result of the California rain and mudslides discussed previously. Our gas production in Argentina for the three months and six months ended June 30, 2004, was reduced by an estimated 165 MMcf and 300 MMcf, respectively, due to the labor strike discussed previously. The decrease in our Bolivian gas production was the result of the anticipated lower sales volumes from Bolivia into Brazil.

	Three Months Ended June 30,			
	2005	2004	Variance	
Costs and expenses:				
Production costs	$ 43,836	$ 34,806	$ 9,030	26%
Transportation and storage costs	4,300	2,741	1,559	57%
Production and ad valorem taxes	8,332	5,519	2,813	51%
Export taxes	16,332	6,706	9,626	144%
Exploration costs	7,429	7,329	100	1%
Gas marketing	15,124	16,480	(1,356)	-8%
General and administrative	16,821	16,791	30	
Depreciation, depletion and amortization	34,353	21,881	12,472	57%
Accretion	1,792	1,629	163	10%
Other operating expenses	1,912	1,213	699	58%
Total costs and expenses	$ 150,231	$ 115,095	$ 35,136	31%
Costs and expenses per BOE:				
Production costs	$ 6.38	$ 5.90	$ 0.48	8%
Transportation and storage costs	0.63	0.46	0.17	37%
General and administrative	2.45	2.85	(0.40)	-14%
Depreciation, depletion and amortization	5.00	3.71	1.29	35%

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	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	Variance	
Costs and expenses:				
Production costs	$ 87,195	$ 70,165	$ 17,030	24%
Transportation and storage costs	8,529	5,061	3,468	69%
Production and ad valorem taxes	15,216	10,825	4,391	41%
Export taxes	29,668	12,912	16,756	130%
Exploration costs	17,755	8,565	9,190	107%
Gas marketing	32,666	30,551	2,115	7%
General and administrative	34,171	34,856	(685)	-2%
Depreciation, depletion and amortization	67,750	45,967	21,783	47%
Impairment of proved oil and gas properties		3,915	(3,915)	-100%
Accretion	3,539	3,247	292	9%
Other operating (income) expenses	2,929	(3,604)	6,533	-181%
Total costs and expenses	$ 299,418	$ 222,460	$ 76,958	35%
Costs and expenses per BOE:				
Production costs	$ 6.39	$ 6.08	$ 0.31	5%
Transportation and storage costs	0.62	0.44	0.18	41%
General and administrative	2.50	3.02	(0.52)	-17%
Depreciation, depletion and amortization	4.96	3.99	0.97	24%

Production costs. Approximately $5.7 million of the increase in our production costs between the second quarter of 2004 and the second quarter of 2005 relates to the 17 percent increase in our total production on a BOE basis between the same periods. Similarly, approximately $12.9 million of the increase in our production costs between the first six months of 2004 and the first six months of 2005 relate to the 18 percent increase in our total production on a BOE basis between the same periods.

In addition to these increases, during the three months and six months ended June 30, 2005, we incurred approximately $2.2 million ($0.32 per BOE) and $5.7 million ($0.42 per BOE), respectively, to repair damage from the heavy rains and mudslides in California. We expect to spend an additional $2.5 million in total during the third quarter of 2005, bringing the total expected costs of these repairs to $8.2 million. Production costs for the first six months of 2004 included $1.9 million ($0.16 per BOE) for costs to repair damage resulting from fires in California during late 2003.

Transportation and storage costs. The increases between the second quarter of 2004 and the second quarter of 2005 and between the first six months of 2004 and the first six months of 2005 are primarily the result of trucking costs associated with our new Yemen production area. We began incurring these costs in the second quarter of 2004 to deliver oil to a nearby processing facility and we produced substantially higher volumes in 2005 compared to 2004. Our pipeline to the processing facility was completed and placed in service during July 2005, which will reduce our transportation cost per barrel in Yemen.

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Production and ad valorem taxes. Higher oil and gas prices and our increased U.S. production resulted in increases in production and ad valorem taxes between the second quarter of 2004 and the second quarter of 2005 and between the first six months of 2004 and the first six months of 2005.

Export taxes. The increases in Argentine export taxes between the second quarter of 2004 and the second quarter of 2005 and between the first six months of 2004 and the first six months of 2005 resulted from higher oil prices between the same periods and export tax rates. The effective export tax rate increased from 16.7 percent to 20.0 percent in May 2004 and was further increased in August 2004. The average effective export tax rate for the second quarter of 2005 on our exported volumes was 31.0 percent.

Exploration costs. Exploration costs for the second quarter of 2005 consisted of $3.7 million for seismic and other geological and geophysical costs and $3.7 million for unsuccessful exploratory drilling, primarily in Yemen. During the second quarter of 2004, our exploration costs were comprised of $1.7 million for seismic and other geological and geophysical costs, $4.4 million for unsuccessful exploratory drilling, primarily in Italy, and $1.2 million for impairments of unproved leasehold costs, primarily in the U.S.

Exploration costs for the first six months of 2005 consisted of $10.0 million for seismic and other geological and geophysical costs, $6.3 million for unsuccessful exploratory drilling, primarily in Yemen, and $1.4 million for impairments of unproved leasehold costs. During the first six months of 2004, our exploration costs were comprised of $2.9 million for seismic and other geological and geophysical costs, $4.4 million for unsuccessful exploratory drilling, primarily in Italy, and $1.3 million for impairments of unproved leasehold costs.

Depreciation, depletion and amortization. Approximately $8.9 million of the increase in our depreciation, depletion and amortization expense from the second quarter of 2004 to the second quarter of 2005 relates to the 24 percent increase in our amortization rate per BOE between the same periods and the remaining $3.6 million of the increase relates to the 17 percent increase in our production on a BOE basis between the periods. Approximately $13.3 million of the increase in our depreciation, depletion and amortization expense from the first six months of 2004 to the first six months of 2005 relates to the 24 percent increase in our amortization rate per BOE between the same periods and the remaining $8.5 million of the increase relates to the 18 percent increase in our production on a BOE basis between the periods. The increases in our amortization rates were primarily a result of our acquisitions of producing properties in the Argentina San Jorge basin in September 2004 and in the Gulf Coast area of Alabama in December 2004 and the impact of increased production on certain U.S. fields which had higher finding and development costs.

Impairment of proved oil and gas properties. In the first quarter of 2004, we recorded impairment expense of $3.9 million related to one proved oil and gas property in the U.S. This impairment resulted from a revision of our estimate of that property s proved oil and gas reserves based on its production level in early 2004. No impairments were required in the second quarter of 2004 or in the first six months of 2005.

Other operating (income) expense. In the first quarter of 2004, we recorded a gain of $6.0 million from a settlement of a certain contract claim that we had against a third party. There was no similar income in the second quarter of 2004 or in the first six months of 2005.

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	Three Months Ended June 30, 2005	2004	Variance	
Non-operating (income) expense:				
Interest expense	$ 11,600	$ 12,674	$ (1,074)	-8%
Losses on derivative transactions	2,728	440	2,288	520%
(Gain) loss on disposition of assets	(16)	4	(20)	-500%
Foreign currency exchange (gain) loss	1,069	(1,969)	3,038	-154%
Other non-operating income	(726)	(162)	(564)	348%
Net non-operating expense	$ 14,655	$ 10,987	$ 3,668	33%

	Six Months Ended June 30, 2005	2004	Variance	
Non-operating (income) expense:				
Interest expense	$ 23,155	$ 26,695	$ (3,540)	-13%
Losses on early extinguishment of debt		9,903	(9,903)	-100%
Losses on derivative transactions	43,444	444	43,000	9685%
Gain on disposition of assets	(16)	(55)	39	-71%
Foreign currency exchange (gain) loss	2,335	(826)	3,161	-383%
Other non-operating income	(1,157)	(173)	(984)	569%
Net non-operating expense	$ 67,761	$ 35,988	$ 31,773	88%

Interest expense. Interest expense decreased between the second quarter of 2004 and the second quarter of 2005 due to a 22 percent reduction in our average debt outstanding and decreased between the first six months of 2004 and the first six months of 2005 due to a 21 percent reduction in our average debt outstanding. These decreases were partially offset by increases in our average interest rate of 16 percent between the second quarter of 2004 and the second quarter of 2005 and nine percent between the first six months of 2004 and the first six months of 2005. During the first quarter of 2004, we advanced funds under our revolving credit facility to redeem the entire $150 million principal balance of our 9 $^{3}/4$% senior subordinated notes due 2009. We subsequently paid off the balance on our revolving credit facility with cash on hand and proceeds from the November 2004 sale of our Canadian operations.

Loss on early extinguishment of debt. In connection with the redemption of our senior subordinated notes discussed above, we were required to pay call premiums on the notes and expense certain associated deferred financing costs and discounts related to the notes, resulting in a loss on early extinguishment of debt of $9.9 million, $6.0 million after tax, in the first quarter of 2004. There was no such charge in the second quarter of 2004 or in the first six months of 2005.

Losses on derivative transactions. In the first quarter of 2005, we recorded losses on derivative transactions of $41.0 million related to realized and unrealized market value adjustments of derivative commodity instruments that did not qualify or ceased to qualify for hedge accounting. There were no similar charges in the first six months of 2004 or in the second quarter of 2005. We also recorded losses for hedge ineffectiveness of $2.7 million and $0.4 million for the second quarters of 2005 and 2004, respectively, and $2.5 million and $0.4 million for the six months ended June 30, 2005 and 2004, respectively.

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Beginning in September 2004 and continuing through February 2005, the differential between the NYMEX index price for crude oil and other U.S. crude oil postings, particularly on the West Coast, widened. Although the NYMEX crude oil index prices increased, many crude oil postings under which we sell our oil did not increase at the same rate. This market fluctuation caused us to conclude that most of our crude oil hedges were no longer highly effective in achieving offsetting changes in the cash flows of the physical transactions. In accordance with SFAS 133, we discontinued hedge accounting for these contracts beginning in September and recorded the changes in the fair value of these contracts as a charge to losses on derivative transactions. As of March 1, 2005, we determined that the correlation indicated that our existing oil price swap agreements will again be highly effective in achieving offsetting changes in the cash flows of the physical transactions and, accordingly, we redesignated all of our oil price swap contracts as cash flow hedges and resumed hedge accounting for these contracts as of March 1, 2005.

Foreign currency exchange gains and losses. Our foreign currency exchange gains and losses primarily relate to our operations in Argentina. Most of our assets and liabilities in Argentina are U.S. dollar-denominated. However, of our balances that are denominated in the Argentine peso, we generally have more peso-denominated liabilities than peso-denominated assets. Therefore, when the peso weakens against the dollar, we generally have foreign currency exchange gains and when the peso strengthens against the dollar, we generally have foreign currency exchange losses.

In the second quarter of 2004, the Argentina peso weakened against the U.S. dollar with the peso-to-dollar exchange rate increasing from 2.86 to 2.97 from March 31, 2004, to June 30, 2004, resulting in a $2.0 million gain. In the second quarter of 2005, the peso strengthened against the dollar with an exchange rate of 2.92 at March 31, 2005, compared to 2.90 at June 30, 2005, resulting in a $1.1 million loss.

In the first six months of 2004, the peso weakened against the dollar with the exchange rate of 2.94 at December 31, 2003, compared to 2.97 at June 30, 2004, resulting in a $0.8 million gain. In the first six months of 2005, the peso strengthened against the dollar with an exchange rate of 2.98 at December 31, 2004, compared to 2.90 at June 30, 2005, resulting in a $2.3 million loss.

Cash Flows

Our primary source of cash during the first six months of 2005 was funds generated from operations. The cash was primarily used to fund capital expenditures and acquisitions of producing properties and pay dividends, with the remainder increasing our cash position by $31.6 million. See below for additional discussion of our cash flows from operating activities.

	Six Months Ended June 30,		
	2005	2004	Change
Cash provided (used) by (in thousands):			
Operating activities - continuing operations	$ 185,330	$ 119,793	$ 65,537
Operating activities - discontinued operations		22,415	(22,415)
Investing activities - continuing operations	(155,290)	(98,087)	(57,203)
Investing activities - discontinued operations		(16,123)	16,123
Financing activities	2,045	(13,163)	15,208

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Cash provided by continuing operations increased 55 percent to $185.3 million in the first six months of 2005 compared to $119.8 million in the first six months of 2004. Increases in production from continuing operations and higher product prices for the first six months of 2005 compared to the same period in 2004 led to the increase. Higher revenues more than offset higher production costs and export taxes. We had $31.8 million of cash used by changes in working capital for the first six months of 2005 compared to $10.2 million of cash used by changes in working capital for the first six months of 2004. See Results of Operations and Period to Period Comparison for further discussion.

Investing activities in the first six months of 2005 included capital spending of $134.2 million on a cash basis, or 72 percent of cash provided by continuing operations. This compares to capital spending in the first six months of 2004 of $97.2 million, or 81 percent of cash provided by continuing operations. Cash used by investing activities in the first six months of 2005 also includes $12.8 million for payments on derivative financial instruments that did not qualify, or ceased to qualify, for hedge accounting.

Cash used by financing activities in the first six months of 2004 reflects the redemption of the entire $150 million principal balance of our 9 $^{3}/4$% senior subordinated notes due 2009, funded by borrowings on our revolving credit facility.

Capital Expenditures

Our oil and gas capital expenditures in the first six months of 2005 were as follows (thousands):

(In thousands)	**U.S.**	**Argentina**	**Bolivia**	**Yemen**	**Other**	**Total**
Acquisitions:						
Unproved properties	$ 7,522	$	$	$	$	$ 7,522
Proved properties	7,665	1,389				9,054
Exploratory	9,152	185		5,916	193	15,446
Development	38,714	61,340		11,885		111,939
	$ 63,053	$ 62,914	$	$ 17,801	$ 193	$ 143,961

At June 30, 2005, our unproved oil and gas properties included the following (in thousands):

U.S.:	
Unproved leasehold costs	$ 16,703
Unevaluated exploratory drilling	4,148
	20,851
Yemen:	
Unproved leasehold costs	2,650
Unevaluated exploratory drilling	11,186

	13,836
	$ 34,687

Future exploration expense and earnings may be impacted to the extent our future exploration activities are unsuccessful in discovering commercial oil and gas reserves in sufficient quantities to recover our costs.

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The timing of most of our capital expenditures is discretionary with no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. We use internally-generated cash flows to fund our capital expenditures other than significant acquisitions. As a result of the continued strong price environment and the positive results from our development drilling program in the U.S. and Yemen, we have increased our 2005 capital expenditure budget to $285 million, exclusive of acquisitions. The increases were primarily allocated to development activities in the U.S. and Yemen. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. We are actively pursuing additional acquisitions of oil and gas properties. Subsequent to June 30, 2005, we signed agreements to purchase certain oil and gas properties in the U.S. for approximately $52 million. In addition to internally-generated cash flows and advances under our revolving credit facility, we may seek additional sources of capital to fund any future significant acquisitions, however, no assurance can be given that sufficient funds will be available to fund our desired acquisitions.

Capital Resources and Liquidity

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

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

Our revolving credit facility consists of a senior secured credit facility maturing in May 2008 with availability governed by a borrowing base determination. Our availability under the revolving credit facility is reduced by our outstanding letters of credit. The borrowing base (currently $350 million) is based on the banks evaluation of our oil and gas reserves. The amount available to be borrowed under the revolving credit facility is limited to the lesser of the borrowing base or the facility size, which is currently set at $300 million. The next borrowing base redetermination will be in November 2005. As of June 30, 2005, we had unused availability under our revolving credit facility of $295.6 million (considering outstanding letters of credit of approximately $4.4 million).

Our internally generated cash flows, results of operations and financing for our operations are dependent on oil and gas prices. Realized oil and gas prices for the first six months of 2005 were 22 percent and 27 percent higher, respectively, compared to the first six months of 2004. These prices have historically fluctuated widely in response to changing market forces. For the first six months of 2005, approximately 73 percent of our production from continuing operations was oil. We believe that our cash flows and unused availability under our revolving credit facility are sufficient to fund our planned capital expenditures for the foreseeable future. To the extent oil and gas prices decline, our earnings and cash flows from operations may be adversely impacted. Prolonged periods of low oil and gas prices could cause us to not be in compliance with maintenance covenants under our revolving credit facility and could negatively affect our credit statistics and coverage ratios and thereby affect our liquidity.

Contractual Obligations

Our contractual obligations have not changed significantly since December 31, 2004.

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Inflation

During the first six months of 2005, the Argentine inflation rate amounted to 6.1 percent and is expected to be approximately ten percent for all of 2005. In recent years, inflation outside of Argentina has not had a significant impact on our operations or financial condition and is not currently expected to have a significant impact on future periods.

Income Taxes

We incurred a current provision for income taxes from continuing operations of approximately $38.6 million and $28.4 million for the first six months of 2005 and 2004, 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 our 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 our intention, generally, to reinvest such earnings permanently. At December 31, 2004, income considered to be permanently reinvested in certain foreign subsidiaries totaled approximately $425 million. We have paid or accrued foreign income taxes of approximately $230 million related to this income which may be available as a credit against U.S. federal income taxes on such income, if distributed. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed because the amount of foreign taxes eligible for credit against U.S. federal income taxes on any such distribution will be determined based on facts and circumstances at the time of any actual distribution.

During the first quarter of 2005, we reversed approximately $13.1 million of contingent liabilities related to U.S. federal and state income taxes. These contingent tax liabilities related to tax benefits resulting from certain filing positions taken for which we initially concluded, for financial reporting purposes, that it was not appropriate, under GAAP, to recognize these benefits until the filing positions taken were sustained under a tax audit. During the first quarter of 2005, federal and state auditors completed audits of our tax returns for the periods involved, with no adjustments related to these filing positions required. Therefore, we concluded that it was now appropriate to recognize these tax benefits for financial reporting purposes. Approximately $10.7 million of these tax benefits related to previously-discontinued operations and are reflected as income from discontinued operations in the accompanying consolidated statement of operations for the six months ended June 30, 2005. The remaining $2.4 million is included as a reduction to the continuing operations deferred income tax provision in the accompanying consolidated statement of operations for the six months ended June 30, 2005.

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

	Six Months Ended June 30,	
	2005	**2004**
U.S. federal statutory income tax rate	35.0%	35.0%
U.S. state income tax (net of federal tax benefit)	0.6	0.1
U.S. permanent differences	(2.9)	(2.0)
Foreign operations	3.1	3.4
	35.8%	36.5%

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The impact of foreign operations is primarily the result of lower tax depreciation, depletion and amortization in Argentina due to the inability to utilize inflation accounting for tax purposes.

We have a U.S. federal net operating loss carryforward of approximately $5.5 million that we expect to fully utilize in 2005.

The American Jobs Creation Act of 2004 (the Jobs Act) introduced a special one-time dividends-received deduction on the repatriation of certain foreign earnings to the U.S., provided certain conditions are met. If certain conditions are met, a 5.25 percent effective income tax rate would apply to eligible repatriations of certain foreign earnings. We are currently evaluating these provisions under the Jobs Act and we are also awaiting interpretive guidance relating to these regulations from either Congress or the Treasury Department. At the current date, we have not determined that we will repatriate any unremitted foreign earnings under the special one-time repatriation provisions of the Jobs Act. However, we continue to evaluate the special one-time repatriation provisions of the Jobs Act and that evaluation could result in our repatriating certain unremitted foreign earnings. The amount of unremitted foreign earnings that we are evaluating for repatriation, including projected 2005 earnings, ranges from zero to $500 million. We expect to complete our evaluation of the amount of repatriation, if any, during 2005. If we were to repatriate certain unremitted foreign earnings under the special one-time repatriation provisions of the Jobs Act in the range noted in the preceding sentence, the income tax effects of such repatriation could range from zero to approximately $26 million.

Critical Accounting Policies and Estimates

Our critical accounting policies are discussed in our 2004 Annual Report on Form 10-K (the 2004 Form 10-K), Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations. There have been no material changes in our critical accounting policies from those reported in the 2004 Form 10-K.

New Accounting Pronouncements

The effects of new accounting pronouncements are discussed in Note 2 to our unaudited consolidated financial statements included elsewhere in this Form 10-Q.

Foreign Operations

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

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Forward-Looking Statements

This Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this Form 10-Q which address activities, events or developments which we expect, believe or anticipate will or may occur in the future are forward-looking statements. The words believes, intends, expects, anticipates, projects, estimates, predicts and similar expressions are also intended to forward-looking statements.

These forward-looking statements include, among others, such things as:

- amounts and nature of future capital expenditures;
- oil and gas prices and demand;
- business strategy;
- production of oil and gas reserves;
- expansion and growth of our business and operations; and
- events or developments in foreign countries, including estimates of oil export levels.

These statements are based on certain assumptions and analyses we made in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform with our expectations and predictions is uncertain. Factors that could cause actual results to differ materially from our expectations include:

- risk factors discussed in our 2004 Form 10-K, and listed from time to time in our filings with the Securities and Exchange Commission;
- oil and gas prices;
- exploitation and exploration successes;
- actions taken and to be taken by the foreign governments as a result of economic conditions;

- continued availability of capital and financing;
- changes in foreign exchange rates and inflation rates;
- general economic, market or business conditions;
- acquisitions and other business opportunities (or lack thereof) that may be presented to and pursued by us;
- changes in laws or regulations; and
- other factors, most of which are beyond our control.

Consequently, all of the forward-looking statements made in this Form 10-Q are qualified by these cautionary statements and there can be no assurance that the actual results or developments anticipated by us will be realized or, even if substantially realized, that they will have the expected consequences to or effects on us or our business or operations. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise.

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Certain Definitions

Unless the context requires otherwise, all references to Vintage, Company, we, our, ours, and us refer to Vintage Petroleum, Inc., its consolidated subsidiaries and its proportionately consolidated general partner interest in a joint venture engaged in exploration and production activities. Below are explanations of certain terms we use in this Form 10-Q:

Basis. The variance in the sales point price for oil or gas production from the reference (or settlement) price for a particular sales transaction.

Bbl. One barrel, or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

BOE. Equivalent barrels of oil, determined using the ratio of six Mcf of gas to one barrel of oil.

BOPD. Barrels of oil production per day.

Btu. British thermal units, the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Gas. Used herein in reference to natural gas. Unless otherwise indicated in this Form 10-Q, gas volumes are stated at the legal pressure base of the state or area in which the reserves are located and at 60 degrees Fahrenheit.

Gross. Used herein in reference to total volume produced or sold without regard to ownership interests.

IMF. The International Monetary Fund.

MBbls. Thousand barrels.

MBOE. Thousand equivalent barrels of oil.

Mcf. Thousand cubic feet.

MMBbls. Million barrels.

MMBOE. Million equivalent barrels of oil.

MMBtu. Million British thermal units.

MMcf. Million cubic feet.

Net. Used herein in reference to production that we own less royalties and production due others.

NYMEX. The New York Mercantile Exchange.

Oil. Used herein in reference to crude oil, condensate and natural gas liquids. Condensate means hydrocarbons which are in a gaseous state under reservoir conditions but which become liquid at the surface and may be recovered by conventional separators. Natural gas liquids means hydrocarbons found in natural gas which may be extracted as liquified petroleum gas and natural gasoline.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

Our exposure to commodity price risk is discussed under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations included elsewhere in this Form 10-Q under the sections entitled Oil Prices, Gas Prices and Future Period Price Risk Management.

Interest Rate Risk

Our interest rate risk exposure results primarily from short-term rates, mainly LIBOR-based on borrowings from our commercial banks. To reduce the impact of fluctuations in interest rates, we have historically maintained a portion of our total debt portfolio in fixed-rate debt. At June 30, 2005, all of our outstanding debt was at fixed rates. However, we expect that this relationship will not continue and that a portion of our debt in future periods will be at variable rates. In the past, we have not entered into financial instruments such as interest rate swaps or interest rate lock agreements. However, we may consider these instruments to manage our portfolio mix between fixed and floating rate debt and to mitigate the impact of changes in interest rates based on our assessment of future interest rates, volatility of the yield curve and our ability to access the capital markets in a timely manner.

Because we had no outstanding borrowings under variable-rate debt instruments as of June 30, 2005, a change in the average interest rate of 100 basis points would result in no change in our net income (loss) and cash flows before income taxes.

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

Long-Term Debt:	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value at 6/30/05
Fixed rate (in thousands)						$ 549,952	$ 549,952	$ 590,750
Average interest rate						8.1%	8.1%	
Variable rate (in thousands)								
Average interest rate								

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Foreign Currency and Operations Risk

International investments represent, and are expected to continue to represent, a significant portion of our total assets. We currently have international operations in Argentina, Bolivia, Yemen and Bulgaria. For the first six months of 2005, our operations in Argentina accounted for approximately 41 percent of our revenues and 39 percent of our total assets. During the first six months of 2005, our operations in Argentina represented our only foreign operation accounting for more than 10 percent of our revenues from continuing operations or total assets. We continue to identify and evaluate international opportunities, but we currently have no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, our 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.

Our international operations 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, as well as labor unrest, could restrict or increase the cost of our foreign operations and could negatively impact our net realized oil and gas prices;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive royalty and tax claims could increase costs of our foreign operations or decrease our net realized oil and gas prices;
- expropriation of our property could result in loss of revenue, property and equipment;
- civil uprisings, riots, terrorist attacks and wars could make it impractical to continue operations, adversely affect both budgets and schedules and expose us 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 our ability to fund foreign operations or may make foreign operations more costly.

We do not currently maintain political risk insurance. However, we will consider obtaining such coverage in the future if we deem conditions so warrant.

Argentina. As a result of more than three years of economic instability and substantial withdrawals from the banking system, in early December 2001, the Argentine government, under President Fernando de la Rua, instituted restrictions that prohibit certain foreign money transfers without Central Bank approval and limit cash withdrawals from bank accounts to personal transactions in small amounts, with certain limited exceptions.

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 his successor, Adolfo Rodriguez Saa, immediately announced default on Argentina s $140 billion sovereign debt.

In early January 2002, the Argentine congress conferred power to Eduardo Duhalde, who enacted temporary measures intended to achieve economic stability and avoid default on multilateral debts. On January 6, 2002, the Argentine government abolished its convertibility law that required an exchange of one peso to one U.S. dollar. The exchange rate at June 30, 2005, was 2.90 pesos to one U.S. dollar. The devaluation of the peso reduced our gas revenues and peso-denominated costs. Our oil revenues remain valued on a U.S. dollar basis.

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Monetary assets and liabilities denominated in pesos at June 30, 2005, were as follows (in thousands):

	Peso Balance	U.S. Dollar Equivalent
Current assets	7,264	$ 2,509
Current liabilities	(131,003)	(45,251)
Non-current liabilities	(71,869)	(24,825)
Net monetary liabilities	(195,608)	$ (67,567)

On February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. On May 11, 2004, the Argentine government increased the tax to 25 percent. Because the tax is applied on the sales value after the tax, the net effect of the 20 and 25 percent rates was 16.7 and 20 percent, respectively. On August 6, 2004, the Argentine government further increased the export tax rates for oil exports. The export tax now escalates from 25 percent (20 percent effective rate) to a maximum rate of 45 percent (31 percent effective rate) of the realized value for exported barrels as West Texas Intermediate posted prices per Bbl increase from less than $32.00 to $45.00 and above. This tax is limited by law to a maximum term through February 2007.

We currently export approximately 35 percent of our Argentine oil production. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved toward parity with the U.S. dollar-denominated export values, net of the export tax. The export tax is deducted for income tax purposes but is not deducted in the calculation of royalty payments.

In accordance with Executive Decree 1589/89, companies engaged in oil and gas production activities are granted the right to freely sell and dispose of their hydrocarbons production. Furthermore, companies are entitled to collect export sales proceeds outside of Argentina and maintain up to 70 percent of U.S. dollar collections outside the country. According to the decree, companies should repatriate the remaining 30 percent of export collections through the exchange markets of Argentina. This requirement places no significant limitations on us based upon our cash flow projections.

Beginning in December 2001, as a result of the economic crisis in the country, Argentina enacted several emergency decrees, including the reinstatement of foreign exchange controls and the mandatory repatriation of most export proceeds. The emergency decrees created some confusion in relation to the regime established under Executive Decree 1589/89, which allows hydrocarbons producers to retain 70 percent of their export collections outside of Argentina. In order to address this matter, Executive Decree No. 2703/02 was issued on December 27, 2002, which confirmed the right to maintain 70 percent of export proceeds outside the country effective January 1, 2003, and therefore did not address transactions which occurred during 2002 after the emergency decrees. We have collected and maintained as much as 70 percent of export proceeds in U.S. dollar bank accounts under the regime established by Executive Decree No. 1589/89 including transactions which occurred during 2002. Although we believe we have acted in accordance with the emergency measures and Executive Decrees in place during 2002, we are aware that the Argentine Central Bank has inquired about certain transactions made by other producers related to retention of export proceeds outside the country during the period in question.

On November 5, 2004, we received a letter from the Ministry of Economy of the Argentine Province of Santa Cruz requesting that royalty payments made since March 2002 be amended to eliminate the market impact of the Argentine export tax on sales to domestic refiners. We believe this request is made without merit, as royalties are calculated and paid on the actual prices received from third party purchasers.

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On December 24, 2004, the Secretary of Energy issued Administrative Resolution 1679/2004, in order to alleviate shortages in domestic diesel markets by insuring adequate oil supplies to Argentine refiners. The terms of the resolution require producers to submit evidence to the Secretary of Energy that its oil to be exported has been offered to domestic refiners prior to the government s issuance of export permission. On July 8, 2005, the Secretary of Energy issued Administrative Resolution 878/2005 which provides an on-going exclusion for any oil volumes that were under fixed-term export sales contracts at December 23, 2004. Every four months, the Secretary of Energy will determine whether this exclusion will continue.

After a year of negotiations, on January 24, 2003, the IMF executed a transitional $6.8 billion, eight-month stand-by credit arrangement to provide financial stability through the presidential elections. After a successful transition of government, and as a result of restoring a measure of economic stability and growth during 2002, in September 2003, the IMF approved a $13.5 billion stand-by credit arrangement, to be disbursed in stages over a three-year period, to succeed the transitional arrangement that expired on August 31, 2003. The economic program to which the Argentine government and the IMF agreed is based on a fiscal framework to meet growth, employment, and social objectives, while providing a basis for normalizing relations with creditors and ensuring debt sustainability. Additionally, they agreed to a strategy to assure strengthening of the banking system, to facilitate increases in bank lending, and to further institutional and tax reforms to facilitate corporate debt restructuring and fundamental improvements to the investment climate. On January 28, 2004, the IMF completed and approved its first review of Argentina s performance under the three-year program. On March 22, 2004, the second review and disbursement of the next $3.1 billion tranche was approved. A third review is pending in conjunction with negotiations on a new stand-by credit agreement. On January 12, 2005, the Argentine government announced a debt swap offer to external creditors. The offer commenced on January 14, 2005, and concluded on February 25, 2005.

On March 3, 2005, the Argentine government announced a successful conclusion to the sovereign debt swap, reporting that 76 percent of bond holders will participate in the exchange. The bonds declared in default in December 2001 have a face value of $81.8 billion, and including unpaid interest, now amount to approximately $103 billion. The debt offered in exchange will be issued for approximately $35.2 billion. After completion of the transaction, total public debt-service costs will be reduced from approximately $10 billion to approximately $3 billion per year. How the Argentine government intends to deal with those bondholders who did not participate in the exchange and other issues outstanding, such as an increase to public utility tariffs, a new loan to govern the fiscal relationship between the federal government and provinces and reform of the banking system must still be addressed prior to signing a new stand-by credit agreement between Argentina and the IMF.

On January 2, 2003, at the Argentine government s request, crude oil producers and refiners agreed to limit amounts payable for certain 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 West Texas Intermediate posted price and the maximum price would be payable once the West Texas Intermediate posted price fell 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 the West Texas Intermediate posted price falls below the maximum price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for 10 consecutive days, which occurred on February 24, 2003.

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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. This agreement, which was extended several times under similar terms, expired on April 30, 2004. At June 30, 2005, the accumulated balance of amounts which we may charge to domestic oil purchasers in Argentina, if the West Texas Intermediate posted price decreases below the established maximum price in the future, was approximately $7.5 million, excluding interest. We do not have the right to invoice for such amounts until such time as the West Texas Intermediate posted price declines below the established price cap of $28.50. Accordingly, we have adopted a revenue recognition accounting policy for this potential revenue in which we will record such revenue only upon the receipt of payment for this additional billing due to the uncertainty of recovery of such amounts and the timing thereof. During 2004 and the first six months of 2005, we did not record any revenue under this agreement. Cumulatively, we have sold approximately 2.0 MMBbls of net oil production under the agreement. We have not recorded revenue nor a receivable for any amounts above the $28.50 per Bbl maximum that have not yet been received. Repayments received from refiners will be recorded as revenues when received.

Bolivia. On July 18, 2004, voters approved President Carlos Mesa s public referendum on several proposed changes in Bolivia s Hydrocarbon Law, including the export of Bolivian gas. As a result of the referendum, on July 30, 2004, President Mesa presented his proposed Hydrocarbons Law reform bill to the Bolivian congress for consideration. This proposal included both increased state control over hydrocarbons commercialization and a new taxation regime. Members of congress and rival political parties proposed numerous changes to President Mesa s reform bill. In early March 2005, political tensions escalated as the Bolivian congress voted among rival proposals concerning the bill s new taxation regime. Leftist opposition groups, led by Evo Morales and the socialist M.A.S. party, demanded that President Mesa s taxation reform proposals be abandoned in favor of increasing royalty rates from the current 18 percent level to a new rate of 50 percent. On March 7, 2005, President Mesa submitted his letter of resignation to the Bolivian congress in protest of the proposal and in response to demonstrations and blockades initiated by the opposition groups; however on March 8, 2005, the congress voted unanimously to reject his resignation.

On March 15, 2005, the lower house of the Bolivian congress approved a hydrocarbons bill that established fixed royalties at the current level of 18 percent, introduced a new production tax of 32 percent and enabled the government to mandate that existing concession agreements be migrated to new agreements that comply with the newly proposed law. On April 29, 2005, the Bolivian senate approved a modified version of the bill which, among other things, provided for reducing the new production tax rate on marginal and minor fields; however, the reduced rate and the term minor field are not defined in the bill. On May 5, 2005, the lower house of congress approved the bill as modified by the senate. The bill was then sent to President Mesa for his signature or veto within ten days. Since the bill was a product of congressional compromise and did not satisfy the demands of either the leftist groups or the pro-business sectors, the bill lacked the backing of either faction. President Mesa called for a national dialogue between congress and social organizations in order to resolve the deadlock, but neither faction was willing to take part. Unwilling to take responsibility for increasing the tax burden and possibly provoking lawsuits from the energy sector and wanting to pacify protestors demonstrating in La Paz and other urban centers, President Mesa neither signed nor vetoed the bill and on May 19, 2005, congress officially ratified the compromise bill, creating the new Hydrocarbon Law No. 3058.

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With the ratification of the new hydrocarbons law, protests intensified with additional strikes and road blocks as disappointed leftist groups demanded an amendment to the new law to raise taxes even further, calling for re-nationalization of hydrocarbons and creation of a constituent assembly to write a new constitution for the country. President Mesa also faced extreme pressure from the petroleum-rich and pro-business Santa Cruz and Tarija provinces, which advocated greater autonomy from the central government in making economic decisions apart from the new hydrocarbon law. On June 6, 2005, after three weeks of intensifying protests, with road blocks and strikes extending throughout the nation, and having lost the support of congress by not ratifying the hydrocarbon bill, President Mesa again offered his resignation.

As it became clear that congress would accept President Mesa s resignation, the focus of the protests turned from the hydrocarbon legislation and economic policy-making to the selection of President Mesa s successor, since there was no vice president to take his place. Constitutionally, Mesa s successor should have been Senate leader Hormando Vaca Diez, a right-leaning politician from the Santa Cruz province and political rival of Evo Morales, followed by lower house leader Mario Cossio and Supreme Court Chief Justice Eduardo Rodriguez. Evo Morales called on indigenous groups to prevent legislators from taking session and passing the succession to either Vaca Diez or Cossio. With lawmakers unable to meet in the capital city of La Paz amidst violent protests, congress was summoned to the historical capital of Sucre to decide the President s fate and choose a successor. The violent protests followed congress to Sucre and, mindful of opposition to their succession, Vaca Diez and Cossio resigned their right to the presidency. On June 10, 2005, Chief Justice Eduardo Rodriguez was sworn in as Bolivia s new president, becoming the third leader to serve during Bolivia s current presidential term. President Rodriguez has presented himself as a transitional leader and has, with the approval of congress, managed to calm the strikes and protests by calling for early presidential, general, and for the first time, provincial governor elections on December 4, 2005. Tensions were also lowered when the Santa Cruz Province agreed to delay its autonomy referendum until July 2, 2006.

In July 2005, major foreign oil and gas production companies notified the Bolivian government of certain investment disputes, as defined under their respective countries bilateral investment treaties, with the government of Bolivia. The companies have requested formal meetings to negotiate amicable solutions to their investment disputes within 180 days, according to procedures in the bilateral investment treaties, or the disputes will be taken to arbitration courts. On August 1, 2005, we also notified the Bolivian government of certain investment disputes caused by actions of the Bolivian government, including, but not limited to, certain provisions in the new Hydrocarbon Law No. 3058, and we have requested formal conversations and negotiations to arrive at an amicable solution to those disputes within 90 days.

During April 2005, the M.A.S. and other opposition parties questioned the legality of concession agreements, which were signed by the state oil company, Y.P.F.B., and the companies. We believe the concession agreements between the Bolivian government and us are valid and the question of their legality is without merit.

As of December 31, 2004, our operations in Bolivia represented 18 percent of our total proved reserves and four percent of our standardized measure of discounted future net cash flows relating to proved oil and gas reserves (Standardized Measure). Until the Bolivian government issues further regulations regarding exactly how the new hydrocarbons law will affect marginal and minor fields, we are unable to precisely determine the law s effect on us. However, we believe that the negative impact of these new laws and regulations will not have a material adverse impact on our consolidated proved reserves, Standardized Measure, financial condition or cash flows.

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In March 2004, the Bolivian government enacted a new tax on all banking transactions, except for payments made to the Bolivian government. The tax is effective for two years beginning July 1, 2004, and will be 0.3 percent for the first year and 0.25 percent the second year. This tax has not had a significant impact on our operations and we do not expect it to have a significant impact on future periods.

During August 2004, in response to protests concerning high oil prices, the Bolivian government issued Decree 27691, which limited the amounts that condensate producers could invoice Bolivian refiners to a maximum price of $27.11 per Bbl. The decree also established a floor price of $24.53 per Bbl.

On January 7, 2005, the Bolivian government issued Executive Decree 27967, stating that prices in the internal Bolivian gas distribution market could not exceed the average of the last three natural gas purchase agreements registered with the Superintendent of Hydrocarbons. In accordance with the Executive Decree, on February 3, 2005, the Superintendent of Hydrocarbons issued Resolution SSDH 124-2005 determining the new maximum price in the Bolivian gas distribution market to be $0.80 per Mcf, effective February 4, 2005. Its terms are effective until April 30, 2006. However, on April 29, 2005, the Bolivian Government issued Executive Decree 28106, modifying Executive Decree 27697, effectively raising prices that could be charged in the gas distribution market. In accordance with Executive Decree 28106, on May 9, 2005, the Superintendent of Hydrocarbons issued Resolution SSDH 0605-2005, establishing the new maximum price in the Bolivian gas distribution market at $0.98 per Mcf, effective May 10, 2005, and its terms are effective until April 30, 2006. Prices in all natural gas purchase agreements in place with Bolivian local distribution companies prior to the resolution can be modified in accordance with the terms of the new resolution. In the last six months of 2005 and in 2006, we have contracted volumes of 0.5 Bcf and 0.3 Bcf, respectively, which are impacted by the decree. Any impact on us resulting from Executive Decree 27967 and Resolution SSDH 124-2005 was offset by the new Executive Decree 28106 and Resolution SSDH 0605-2005.

Bolivian gas markets have historically been limited to exports to Brazil via the Bolivia-to-Brazil gas pipeline and to those internal gas sales necessary to meet Bolivian industrial and consumer demand. We are working to increase sales in both of these areas and we currently have capacity to deliver gas volumes in excess of our contracted volumes. The current daily productive capacity of our properties in Bolivia is approximately 46 MMcf of gas, gross, and 28 MMcf of gas, net. During the past several years, Bolivian gas reserve growth has exceeded the demand growth in Bolivia s existing markets. Therefore, we believe substantial competition for gas markets will continue at least until new market areas are established. On April 21, 2004, the Argentine and Bolivian governments agreed to a gas supply arrangement for 141 MMcf per day of gas to Argentina for a six-month period beginning in May 2004, and in July 2004, the government signed a letter of intent to increase those exports by 88 MMcf per day. In July 2005, the temporary contract to export Bolivian gas to Argentina was extended through the end of 2006 and the volumes were increased to 272 MMcf per day. On October 14, 2004, the Argentine and Bolivian governments signed a letter of intent for Bolivia to export up to 706 MMcf per day to Argentina and these exports are estimated to commence by the end of 2006.

In 1987, the boliviano replaced the peso and became Bolivia s currency. 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, 2005, was 8.1 bolivianos to one U.S. dollar. Since our gas revenues are received in U.S. dollars, we believe that any currency risk associated with our Bolivian operations would not have a material impact on our financial position or results of operations.

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Yemen. Yemen has been classified as a low-income, developing country by the World Bank. Trade and other external economic links have been limited, with the exception of the oil sector, which accounts for more than 25 percent of Yemen s gross domestic product. The production sharing agreements under which private investors operate are clear and unambiguous, resulting in most of the country s foreign investment being concentrated in the oil sector.

The government has relaxed the broader regulatory environment to encourage additional foreign investments. However, obstacles such as an insufficient infrastructure continue to exist. Necessary economic reforms began during 1995 and were supported by both the IMF and the World Bank. The reforms were targeted to enable a more market-based and private-sector-driven economy and more integration into world markets, all within the context of broad financial and macro-economic stability. These reforms continue to influence Yemen s economic policies today.

In July 2005, the government of Yemen reduced certain subsidies on fuel prices, nearly doubling the price to consumers for gasoline, diesel and kerosene, as part of its economic reform program with the IMF. The citizens responded to this price increase with violent protest and riots. In an attempt to ease public tension, the government announced on July 26, 2005, that it would partially reduce fuel prices, but a long-term solution to the government-sustained subsidies has not yet been announced.

Yemen introduced a floating exchange rate system in 1996, which had helped the Yemeni rial to stabilize in real terms. The Yemeni central bank has often attempted to stabilize the exchange rate in times of trouble through interest rate policy and the auctioning of foreign exchange to moneychangers and banks. The exchange rate on June 30, 2005, was 192 rials to one U.S. dollar, after experiencing a gradual depreciation during 2004. Since our oil revenues are received in U.S. dollars, we believe that any currency risk associated with our Yemen operations would not have a material impact on our financial position or results of operations.

Yemen has taken significant steps to stabilize its political environment since the end of its civil war in 1994. The government is dominated by northern Yemen, located in the capital city of Sana a and headed by President Ali Abdullah Saleh, who is a member of the General People s Congress. The General People s Congress has held power since the mid-1990 s and a regime change is considered unlikely. Although President Saleh, who has been in office since 1978, announced in July 2005 his intention to not seek re-election in 2006, we do not expect a significant change in governmental policy. Civil society is relatively weak and tribal structures remain powerful. Concerns about terrorism and kidnappings are ongoing security risks. Further concerns about continued implementations of economic reform measures as well as increased government control are ongoing business risks. We have evaluated the risk of operating in Yemen and we believe that the current risks are manageable.

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ITEM 4. CONTROLS AND PROCEDURES

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended) as of June 30, 2005. Our management, including the Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. The inherent limitations in all control systems include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Based upon the evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in our 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 Form 10-Q, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II

OTHER INFORMATION

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Item 1. Legal Proceedings

For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2004.

Item 2. Unregistered Sales of Equity 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

Our Annual Meeting of Stockholders (the Annual Meeting) was held on May 10, 2005, in Tulsa, Oklahoma. At the Annual Meeting, stockholders elected Charles C. Stephenson, Jr. and Joseph D. Mahaffey as Class III Directors. The stockholders also considered and approved Amendment Eight to the Vintage Petroleum, Inc. 1990 Stock Plan and the appointment of Ernst & Young LLP as our independent auditors for the fiscal year ending December 31, 2005. The stockholders considered, but did not approve, the Stockholder Proposal on Climate Change Report.

There were present at the Annual Meeting, in person or by proxy, stockholders holding 62,493,527 shares of our Common Stock, or 94 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:				
Charles C. Stephenson, Jr.	60,984,748	1,508,779	-0-	-0-
Joseph D. Mahaffey	59,915,905	2,577,622	-0-	-0-
2. Ratification of Amendment Eight to the Vintage Petroleum, Inc. 1990 Stock Plan	39,404,475	16,397,386	56,914	6,634,752
3. Ratification of Appointment of Ernst & Young LLP as our Independent Auditors for Fiscal 2005	32,517,417	20,516,396	36,448	-0-
4. Ratification of Stockholder Proposal on Climate Change Report	13,527,063	39,258,428	3,073,333	6,634,703

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Item 5. Other Information

Not applicable

Item 6. 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 or furnished herewith.

10.1	Amendment No. 8 to Vintage Petroleum, Inc. 1990 Stock Plan (filed as Exhibit B to our Proxy Statement for Annual Meeting of Stockholders dated April 6, 2005).
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.

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Signatures

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

VINTAGE PETROLEUM, INC.
(Registrant)

DATE: August 8, 2005

/s/ Michael F. Meimerstorf

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

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