VINTAGE PETROLEUM INC
Form 10-Q
November 08, 2005
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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 September 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 Rule 12b-2 of the Exchange Act). Yes x No ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

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 October 31, 2005
Common Stock, $0.005 Par Value	67,214,748

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VINTAGE PETROLEUM, INC.

FORM 10-Q

THREE MONTHS ENDED SEPTEMBER 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

	September 30, 2005	December 31, 2004
CURRENT ASSETS:		
Cash and cash equivalents	$ 180,624	$ 124,221
Accounts receivable -		
Oil and gas sales	127,995	107,870
Joint operations and other	12,696	12,479
Income taxes receivable	440	31,571
Deferred income taxes	42,110	15,364
Prepaids and other current assets	17,291	23,648
Total current assets	381,156	315,153
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method	2,419,804	2,163,176
Oil and gas gathering systems and plants	23,926	23,926
Other	33,950	31,932
	2,477,680	2,219,034
Less accumulated depreciation, depletion and amortization	1,044,978	942,656
Total property, plant and equipment, net	1,432,702	1,276,378
DEFERRED INCOME TAXES	11,795	13,200
OTHER ASSETS, net	50,151	40,161
TOTAL ASSETS	$ 1,875,804	$ 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

	September 30, 2005	December 31, 2004
CURRENT LIABILITIES:		
Revenue payable	$ 29,164	$ 33,740
Accounts payable - trade	51,205	50,775
Current income taxes payable	24,744	23,565
Derivative financial instruments payable	99,096	27,672
Other payables and accrued liabilities	92,066	73,748
Total current liabilities	296,275	209,500
LONG-TERM DEBT	549,953	549,949
DEFERRED INCOME TAXES	87,715	80,383
LONG-TERM LIABILITY FOR ASSET RETIREMENT OBLIGATIONS	93,590	90,707
OTHER LONG-TERM LIABILITIES	38,112	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, 67,576,817 and 66,541,984 shares issued and 67,033,582 and 66,012,252 shares outstanding, respectively	338	333
Capital in excess of par value	381,951	361,120
Retained earnings	493,883	342,707
Accumulated other comprehensive loss	(56,653)	(13,088)
	819,519	691,072
Less treasury stock, at cost, 543,235 and 529,732 shares, respectively	4,319	4,319
Less unamortized cost of non-vested stock awards	5,041	3,075
Total stockholders equity	810,159	683,678
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 1,875,804	$ 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 September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
REVENUES:				
Oil, condensate and NGL sales	$ 214,623	$ 136,382	$ 566,269	$ 367,320
Gas sales	53,457	49,158	155,509	127,284
Sulfur sales	702	234	2,434	949
Gas marketing	13,313	17,897	48,015	50,131
Total revenues	282,095	203,671	772,227	545,684
COSTS AND EXPENSES:				
Production costs	46,669	34,010	133,864	104,175
Transportation and storage costs	4,163	3,643	12,692	8,704
Production and ad valorem taxes	9,738	5,732	24,954	16,557
Export taxes	19,155	12,778	48,823	25,691
Exploration costs	12,432	12,435	30,187	21,000
Gas marketing	12,307	16,857	44,973	47,409
General and administrative	17,807	13,959	51,978	48,814
Depreciation, depletion and amortization	35,914	26,720	103,664	72,687
Impairment of proved oil and gas properties				3,915
Accretion	1,819	1,685	5,358	4,932
Other operating (income) expense	549	1,671	3,478	(1,933)
Total costs and expenses	160,553	129,490	459,971	351,951
OPERATING INCOME	121,542	74,181	312,256	193,733
NON-OPERATING (INCOME) EXPENSE:				
Interest expense	11,467	12,625	34,622	39,321
Loss on early extinguishment of debt				9,903
(Gain) loss on derivative transactions	(1,420)	14,917	42,024	15,361
Gain on disposition of assets	(925)	(17)	(941)	(72)
Foreign currency exchange (gain) loss	(676)	(285)	1,659	(1,112)
Other non-operating (income) expense	(1,467)	804	(2,624)	630
Net non-operating expense	6,979	28,044	74,740	64,031
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	114,563	46,137	237,516	129,702
INCOME TAX PROVISION:				
Current	41,356	15,701	79,942	44,114

Deferred	989	3,024	6,456	5,115
Total income tax provision	42,345	18,725	86,398	49,229
INCOME FROM CONTINUING OPERATIONS	72,218	27,412	151,118	80,473
INCOME (LOSS) FROM DISCONTINUED OPERATIONS, net of income taxes		(397)	10,743	3,086
NET INCOME	$ 72,218	$ 27,015	$ 161,861	$ 83,559

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 September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
BASIC INCOME PER SHARE:				
Income from continuing operations	$ 1.08	$ 0.42	$ 2.27	$ 1.24
Income (loss) from discontinued operations		(0.01)	0.16	0.05
Net income	$ 1.08	$ 0.41	$ 2.43	$ 1.29
DILUTED INCOME PER SHARE:				
Income from continuing operations	$ 1.07	$ 0.42	$ 2.24	$ 1.23
Income (loss) from discontinued operations		(0.01)	0.16	0.05
Net income	$ 1.07	$ 0.41	$ 2.40	$ 1.28
Weighted average common shares outstanding:				
Basic	67,004	65,283	66,651	64,786
Diluted	67,659	66,043	67,344	65,521

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 NINE MONTHS ENDED SEPTEMBER 30, 2005

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

(Unaudited)

	Common Stock		Treasury	Capital In Excess of	Unamortized Non-Vested	Retained	Accumulated Other Comprehensive	
	Shares	Amount	Stock	Par Value	Stock Awards	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						161,861		161,861
Change in value of derivative financial instruments, net of tax							(43,565)	(43,565)
Total comprehensive income								118,296
Amortization of stock option expense				5				5
Exercise of stock options and tax effects	857	4		13,208				13,212
Issuance of non-vested stock	154	1		4,660	(4,661)			
Amortization of non-vested stock awards and tax effects				3,231	2,499			5,730
Forfeitures of non-vested stock (13,503 shares)				(273)	196			(77)
Vesting of stock rights	24							
Cash dividends declared ($0.16 per share)						(10,685)		(10,685)
BALANCE AT SEPTEMBER 30, 2005	67,577	$ 338	$ (4,319)	$ 381,951	$ (5,041)	$ 493,883	$ (56,653)	$ 810,159

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)

	Nine Months Ended September 30,	
	2005	**2004**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 161,861	$ 83,559
Adjustments to reconcile net income to cash provided by operating activities-		
Income from discontinued operations, net of tax	(10,743)	(3,086)
Depreciation, depletion and amortization	103,664	72,687
Impairment of proved oil and gas properties		3,915
Accretion	5,358	4,932
Dry hole costs, impairments of unproved oil and gas properties and other	25,208	16,733
Provision for deferred income taxes	6,456	5,115
Foreign currency exchange (gain) loss	1,659	(1,112)
Gain on dispositions of assets	(941)	(72)
Loss on early extinguishment of debt		9,903
Stock compensation	4,691	7,091
Non-cash derivative losses	42,024	15,361
Other non-cash items included in net income	923	424
(Increase) decrease in receivables	9,532	(5,532)
Increase in payables and accrued liabilities	11,362	9,923
Other working capital changes	(833)	1,727
Cash provided by continuing operations	360,221	221,568
Cash provided by discontinued operations		34,646
Cash provided by operating activities	360,221	256,214
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures -		
Oil and gas properties	(279,578)	(159,538)
Gathering systems and other	(2,255)	(2,132)
Purchase of company, net of cash acquired		(26,757)
Proceeds from sale of oil and gas properties	4,213	67
Payments on non-hedge derivative transactions	(21,586)	
Other	(9,120)	2,454
Cash used by investing activities - continuing operations	(308,326)	(185,906)
Cash used by investing activities - discontinued operations		(23,785)
Cash used by investing activities	(308,326)	(209,691)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	9,297	11,218

Purchase of treasury stock		(1,202)
Redemption of 9 3/4% Senior Subordinated Notes Due 2009		(157,313)
Advances on revolving credit facility and other borrowings	79,000	370,100
Payments on revolving credit facility and other borrowings	(79,000)	(243,500)
Dividends paid ($0.155 and $0.14 per share, respectively)	(10,299)	(9,042)
Other	5,860	(3,668)
Cash provided (used) by financing activities	4,858	(33,407)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(350)	632
NET INCREASE IN CASH AND CASH EQUIVALENTS	56,403	13,748
CASH AND CASH EQUIVALENTS, beginning of period	124,221	32,264
CASH AND CASH EQUIVALENTS, end of period	$ 180,624	$ 46,012

See notes to unaudited consolidated financial statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

September 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 September 30, 2005, balance sheet are as follows (in thousands):

U.S.:	
Unproved leasehold costs	$ 24,993
Unevaluated exploratory drilling	7,554
	32,547
Yemen:	
Unproved leasehold costs	2,500
Unevaluated exploratory drilling	158

2,658
$ 35,205

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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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Continuing operations	$ 304	$ 1,136	$ 1,682	$ 2,482
Discontinued operations (Canada)		1,197		4,332

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.

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 for which proved reserves have not been found is charged to expense. The Company adopted FSP 19-1 effective July 1, 2005. No adjustment to capitalized exploratory costs was required from this adoption.

As of September 30, 2005, the Company had the following exploration wells capitalized for which the determination of proved reserves is pending (in thousands):

Wells in progress	$ 3,899
Drilling completed - less than one year	3,813
Drilling completed - over one year	
Total exploration drilling costs	$ 7,712

The Company incurred approximately $10.9 million on two exploration wells in Yemen for which the determination of proved reserves was pending. Management completed its evaluation of these wells during the third quarter of 2005. Based on the results of the Company s evaluation, the costs capitalized for these wells, along with $0.1 million of unproved leasehold costs, were charged to expense.

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For the nine months ended September 30, 2005, the changes in capitalized exploratory drilling costs for which the determination of proved reserves is pending were as follows (in thousands):

Balance, beginning of period	$ 11,137
Additions	7,006
Reclassifications to proved oil and gas properties	
Charged to expense	(10,431)
Balance, end of period	$ 7,712

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 or third quarters of 2004 or in the first nine 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 $0.1 million of delineation seismic costs for the nine months ended September 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 September 30, 2005, there were no assets legally restricted for purposes of settling asset retirement obligations. Of the liability for asset retirement obligations balance at September 30, 2005, approximately $0.1 million million is classified as current and is included in other payables and accrued liabilities in the accompanying balance sheet.

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

Liability for asset retirement obligations as of January 1, 2005	$ 93,066
New obligations for wells drilled	1,499
New obligations for wells purchased	179
Costs incurred	(3,374)
Accretion expense	5,358
Liability for asset retirement obligations as of September 30, 2005	$ 96,728

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 September 30, 2005, other payables and accrued liabilities includes $22.3 million of accrued oil and gas capital expenditures.

Derivative Financial Instruments

The Company periodically uses derivative financial instruments 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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Losses under derivative instruments that did not qualify, or ceased to qualify, for hedge accounting	$	$ 15,734	$ 40,962	$ 14,810
Hedge ineffectiveness (gains) losses	(1,420)	(817)	1,062	551
	$ (1,420)	$ 14,917	$ 42,024	$ 15,361

During the nine months ended September 30, 2005, the Company realized $21.6 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 September 30, 2005, the Company had an unbilled potential recovery of approximately $7.2 million under this agreement, excluding interest. During the nine months ended September 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 $2.8 million at September 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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
General and administrative cost reimbursements	$ 720	$ 936	$ 2,111	$ 2,318

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 nine months of 2005 and 2004 and for the third 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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Stock compensation expense - as reported	$ 1,561	$ 1,153	$ 4,691	$ 7,091
Stock compensation expense - pro forma	1,563	1,174	4,710	7,185
Net income - as reported	72,218	27,015	161,861	83,559
Net income - pro forma	72,217	27,002	161,848	83,499
Income per share - as reported:				
Basic	1.08	0.41	2.43	1.29

Diluted	1.07	0.41	2.40	1.28
Income per share - pro forma:				
Basic	1.08	0.41	2.43	1.29
Diluted	1.07	0.41	2.40	1.27

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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 nine 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

Production and ad valorem taxes consist of the following (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004

Gross production taxes	$ 8,283	$ 4,279	$ 20,578	$ 12,199
Ad valorem taxes	1,455	1,453	4,376	4,358

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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 September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
Weighted average common shares outstanding - Basic	67,004	65,283	66,651	64,786
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	333	538	432	553
Dilutive effect of potential common shares issuable upon the vesting of outstanding restricted stock rights	322	222	261	182
Weighted average common shares outstanding - Diluted	67,659	66,043	67,344	65,521

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 nine months ended September 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 nine months ended September 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 nine months ended September 30, 2004:

	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2004
Options excluded from dilution calculations (in thousands)	55	654
Range of exercise prices	$17.31 to $22.94	$15.50 to $22.94
Weighted average exercise price	$19.70	$15.86

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Comprehensive Income

Comprehensive income consists of the following (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Net income	$ 72,218	$ 27,015	$ 161,861	$ 83,559
Foreign currency translation adjustments		9,355		4,525
Changes in value of derivative financial instruments, net of tax	(16,570)	(20,891)	(43,565)	(34,714)
Comprehensive income	$ 55,648	$ 15,479	$ 118,296	$ 53,370

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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Unrealized loss during the period	$ (57,029)	$ (31,939)	$ (123,934)	$ (56,614)
Reclassification adjustment for losses included in net income	29,909	409	52,633	2,342
	(27,120)	(31,530)	(71,301)	(54,272)
Income tax benefit	10,550	10,639	27,736	19,558
Changes in value of derivative financial instruments, net of tax	$ (16,570)	$ (20,891)	$ (43,565)	$ (34,714)

The balance in accumulated other comprehensive loss at both September 30, 2005, and December 31, 2004, relates entirely to changes in the value of derivative financial instruments. Based on oil and gas prices at September 30, 2005, approximately $45.7 million of the $56.7 million balance in accumulated other comprehensive loss at September 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):

	Nine Months Ended September 30,	
	2005	2004
Interest	$ 23,322	$ 27,528
Income taxes:		
U.S.	$ 13,265	$
Argentina	54,000	48,157
Canada (Discontinued operations)		1,243
	$ 67,265	$ 49,400

Approximately $156.0 million of the Company s cash at September 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 September 30, 2005, and December 31, 2004, consisted of the following (in thousands):

	September 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	199,953	199,949
	$ 549,953	$ 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 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 September 30, 2005, the Company had unused availability under its revolving credit facility of $295.3 million (considering outstanding letters of credit of approximately $4.7 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 $18.1 million of accrued interest payable related to its long-term debt at September 30, 2005, and $6.9 million of accrued interest payable at 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 September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
Dividends declared per share	$ 0.055	$ 0.050	$ 0.160	$ 0.145

5. COMMITMENTS AND CONTINGENCIES

The Company had approximately $4.7 million in letters of credit outstanding at September 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 $1.3 million and $1.7 million under these agreements in the nine months ended September 30, 2005 and 2004, respectively, and $0.4 million and $0.7 million under these agreements in the three months ended September 30, 2005 and 2004, respectively. Based on the current fee level, these commitments total approximately $0.3 million for the remainder of 2005, $1.1 million in 2006, $0.2 million in 2007 and $0.3 in each of the years 2008 and 2009.

The Company has future minimum long-term electric power purchase commitments in Argentina of $0.9 million for the remainder of 2005, $3.6 million in 2006 and $5.0 million in 2007. The Company paid $2.7 million and $1.9 million for electric power purchases under these agreements in the nine months ended September 30, 2005 and 2004, respectively, and $0.9 million and $0.8 million in the three months ended September 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 1.8 Bcf for the remainder of 2005, 6.7 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 2.8 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.

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 on 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 September 30, 2005, all of the Company s derivative financial instruments qualified as hedges for accounting purposes.

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During the first nine months of 2004, the Company participated in oil price swap agreements covering 4.4 million barrels of its oil production at a weighted average NYMEX reference price of $30.07 per barrel and gas price swap agreements covering 3.1 million MMBtu of its gas production at a weighted average NYMEX reference price of $5.91 per MMBtu. During the first nine months of 2005, the Company participated in oil price swap agreements covering 3.8 million barrels of its oil production at a weighted average NYMEX reference price of $36.60 per barrel, gas price swap agreements covering 3.5 million MMBtu of its gas production at a weighted average NYMEX reference price of $6.32 per MMBtu and gas price collar agreements covering 8.2 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 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 September 30, 2005, consisted of a current liability of $99.1 million and a long-term liability of $27.1 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:

	Nine Months Ended September 30,	
	2005	2004
U.S. federal statutory income tax rate	35.0%	35.0%
U.S. state income tax (net of federal tax benefit)	1.0	
U.S. permanent differences	(2.1)	0.7
Foreign operations	2.5	2.3
	36.4%	38.0%

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, after-tax income considered to be permanently reinvested in certain foreign subsidiaries totaled approximately $155 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 nine months ended September 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 nine months ended September 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 associated interpretive guidance. No regulations from either Congress or the Treasury Department have been issued. At the current date, the Company has not determined if 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 above, 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.

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

	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2004
Revenues	$ 24,240	$ 74,986
Income (loss) from discontinued operations	$ (581)	$ 3,216
Income tax provision (benefit)	(184)	130
Income (loss) from discontinued operations, net of tax	$ (397)	$ 3,086

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 nine months and three months ended September 30, 2005 and 2004, is shown in the following tables (in thousands):

	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
Nine Months Ended 9/30/05					
External segment revenues	$ 327,887	$ 325,390	$ 8,524	$ 62,411	$
Intersegment revenues					
Depreciation, depletion and amortization expense	48,920	43,442	1,842	7,904	
Operating income (loss)	170,766	157,749	2,240	25,944	(214)
Total assets	757,393	698,203	114,451	79,968	
Capital investments	158,588	98,176		29,894	193
Long-lived assets	663,496	622,143	86,854	54,389	

	Gas Marketing	Corporate	Total
Nine Months Ended 9/30/05			
External segment revenues	$ 48,015	$	$ 772,227
Intersegment revenues	2,754		2,754
Depreciation, depletion and amortization expense		1,556	103,664
Operating income (loss)	3,042	(47,271)	312,256
Total assets	20,216	205,573	1,875,804
Capital investments		2,254	289,105
Long-lived assets		5,820	1,432,702

	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
Nine Months Ended 9/30/04					
External segment revenues	$ 240,749	$ 237,171	$ 11,558	$ 6,075	$
Intersegment revenues					
Depreciation, depletion and amortization expense	35,564	32,437	2,444	593	
Operating income (loss)	99,566	128,092	5,545	2,584	(5,515)
Total assets	527,817	632,359	112,662	44,416	1,748
Capital investments	85,824	100,895		14,693	4,553
Long-lived assets	477,525	559,694	88,981	35,945	

	Gas Marketing	Corporate	Total
Nine Months Ended 9/30/04			
External segment revenues	$ 50,131	$	$ 545,684
Intersegment revenues	2,001		2,001
Depreciation, depletion and amortization expense		1,649	72,687
Operating income (loss)	2,722	(39,261)	193,733
Total assets	17,641	90,332	1,426,975
Capital investments		1,586	207,551

Long-lived assets	5,119	1,167,264

	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
Three Months Ended 9/30/05					
External segment revenues	$ 114,924	$ 122,321	$ 3,276	$ 28,261	$
Intersegment revenues					
Depreciation, depletion and amortization expense	16,683	14,415	603	3,617	
Operating income (loss)	63,775	63,846	542	8,582	1
Total assets	757,393	698,203	114,451	79,968	
Capital investments	95,535	35,262		12,093	
Long-lived assets	663,496	622,143	86,854	54,389	

	Gas Marketing	Corporate	Total
Three Months Ended 9/30/05			
External segment revenues	$ 13,313	$	$ 282,095
Intersegment revenues	1,017		1,017
Depreciation, depletion and amortization expense		596	35,914
Operating income (loss)	1,006	(16,210)	121,542
Total assets	20,216	205,573	1,875,804
Capital investments		814	143,704
Long-lived assets		5,820	1,432,702

	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
Three Months Ended 9/30/04					
External segment revenues	$ 86,245	$ 90,353	$ 4,831	$ 4,345	$
Intersegment revenues					
Depreciation, depletion and amortization expense	13,330	11,434	984	371	
Operating income (loss)	34,254	47,728	2,651	1,827	(6,547)
Total assets	527,817	632,359	112,662	44,416	1,748
Capital investments	33,761	58,333		7,554	537
Long-lived assets	477,525	559,694	88,981	35,945	

	Gas Marketing	Corporate	Total
Three Months Ended 9/30/04			
External segment revenues	$ 17,897	$	$ 203,671
Intersegment revenues	1,075		1,075
Depreciation, depletion and amortization expense		601	26,720
Operating income (loss)	1,039	(6,771)	74,181
Total assets	17,641	90,332	1,426,975
Capital investments		537	100,722
Long-lived assets		5,119	1,167,264

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10. SUBSEQUENT EVENT

On October 13, 2005, the Company announced that it had entered into an Agreement and Plan of Merger dated as of October 13, 2005 (the Merger Agreement), with Occidental Petroleum Corporation, a Delaware corporation (Occidental), and Occidental Transaction 1, LLC, a Delaware limited liability company and wholly-owned subsidiary of Occidental (Merger Sub), under which the Company will be merged with and into Merger Sub and the separate corporate existence of the Company will cease (the Merger). Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of the Company s common stock (the Shares) (other than Shares owned by Occidental, Merger Sub, the Company and not held on behalf of third parties or any stockholders who are entitled to and who properly exercise appraisal rights under Delaware law) will be cancelled and converted into the right to receive 0.42 of a share of Occidental s common stock (the Occidental Common Stock) plus $20.00 in cash (the Mixed Consideration). All outstanding options and unvested stock awards of the Company will be fully vested and converted into the right to receive the fair market value in cash of the Mixed Consideration, using a five-day average trading price of the Occidental Common Stock (ending on the last trading day before the effective time of the Merger), and, in the case of an option, such amount will be reduced by the exercise price per share of such option.

The Merger is conditioned, among other things, on:

- the termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended;
- a Registration Statement on Form S-4 related to the Merger being filed with the Securities and Exchange Commission (the SEC) and becoming effective and not being subject to any stop order by the SEC;
- the shares of Occidental Common Stock to be issued in the Merger being authorized for listing on the New York Stock Exchange upon official notice of issuance;
- the absence of any legal prohibition on completion of the Merger;
- receipt by Occidental and the Company of tax opinions from their respective tax counsel to the effect that the Merger will be treated for Federal income tax purposes as a reorganization within the meaning of Section 368(a) of the Internal Revenue Code;
- the representations and warranties of Occidental and the Company set forth in the Merger Agreement being true and correct in all material respects to the extent specified in the Merger Agreement;
- the approval of the Merger Agreement by the Company s stockholders;
- the performance in all material respects of the parties obligations required to be performed at or prior to the closing of the Merger; and
- the aggregate amount of shares held by stockholders who are entitled to and who properly exercise appraisal rights under Delaware law being less than 10 percent of the total outstanding Shares at the effective time of the Merger.

Occidental and the Company have each agreed to use their reasonable best efforts and, subject to certain limitations, take such actions as are required in connection with obtaining such approvals and satisfying such conditions.

The Merger Agreement contains limited termination rights and, upon the termination of the Merger Agreement under specified circumstances, the Company may be required to pay Occidental a termination fee equal to $75,000,000. The Merger Agreement also includes other representations, warranties and covenants that are customary for transactions of this type.

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Effective March 16, 1999, the Company entered into a Rights Agreement with Mellon Investor Services LLC (formerly known as ChaseMellon Shareholder Services, L.L.C.), as Rights Agent (the Rights Agent), which was subsequently amended by the First Amendment to Rights Agreement dated as of April 3, 2002 (as amended, the Rights Agreement). In connection with the Merger Agreement described above, effective October 13, 2005, the Company entered into the Second Amendment to the Rights Agreement. Among other things, this amendment (a) renders the provisions of the Rights Agreement inapplicable to the Merger by exempting Occidental and Merger Sub from the definition of Acquiring Person and providing that a Distribution Date shall not be deemed to have occurred due to the execution and delivery of the Merger Agreement and the consummation of the Merger; and (b) provides for the termination of the Rights Agreement (except for the rights, obligations and liabilities of the Company and the Rights Agent set forth in Section 18 of the Rights Agreement) immediately prior to the effective time of the Merger.

Effective October 13, 2005, in light of the Merger and the Company s performance through September 30, 2005, and projected performance for the fourth quarter of 2005, the Company s Board of Directors, upon the recommendation of its Compensation Committee, granted bonuses for 2005 under the Vintage Petroleum, Inc. Discretionary Performance Bonus Program to eligible U.S. employees, including executive officers, of the Company. These bonuses are payable to those eligible U.S. employees who remain with the Company until the earlier of the closing of the Merger or February 28, 2006.

Effective October 13, 2005, the Board of Directors, upon the recommendation of its Compensation Committee, established a completion bonus program for the Company s Tulsa office employees, including certain executive officers, and expatriate employees of the Company who remain with the Company through the closing of the Merger. The completion bonus is payable at closing of the Merger, and, if the Merger does not occur, no completion bonuses will be paid. The Company s President and its two Executive Vice Presidents are not eligible to receive completion bonuses.

On December 22, 2004, the Compensation Committee of the Board of Directors of the Company established a performance-based cash bonus program for the Company s Chief Executive Officer. Effective October 13, 2005, the Compensation Committee of the Company s Board of Directors, modified this bonus program to provide that, in the event the Merger occurs, the Company s President will be paid $2.4 million. This amount is payable at the closing of the Merger.

From time to time prior to October 1, 2005, the executive officers of the Company have been granted performance-based non-vested stock rights under the Company s 1990 Stock Plan, as amended. Under these rights, the executive officer has the ability to earn a number of shares of the Company s common stock in the amount of zero to 200 percent of a base number of shares (Base Number) based upon the Company s total stockholder return as compared to the total stockholder return of each company in a peer group of companies selected by the Compensation Committee of the Company s Board of Directors during a three-year performance period. The number of shares earned depends on the Company s rank among the peer group of companies. In the event of a change in control of the Company (as defined in the Company s 1990 Stock Plan, as amended), the executive officer will receive the Base Number. Effective October 13, 2005, the Compensation Committee of the Company s Board of Directors modified such performance-based non-vested stock rights to provide that, in the event the Merger occurs, the executive officer will receive 200 percent of the Base Number.

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On October 13, 2005, the Board of Directors, upon recommendation of its Compensation Committee, granted an additional 75,000 of performance-based non-vested stock rights to the executive officers of the Company and an additional 181,8000 shares of non-vested stock under the Company s 1990 Stock Plan, as amended. The Company s President and its two Executive Vice presidents did not receive any of these awards. Activity for the Company s outstanding shares of common stock subsequent to September 30, 2005, is as follows:

Shares outstanding on September 30, 2005	67,033,582
Issuance of non-vested stock	181,800
Forfeiture of non-vested stock	(4,634)
Exercise of stock options	4,000
Shares outstanding on October 31, 2005	67,214,747

Effective October 13, 2005, the Company has agreed to make payments to each of its Tulsa-based employees equal to the effect of any excise tax imposed by Section 4999 of the Internal Revenue Code on any excess parachute payment made to such employee in connection with the Merger. In general, Section 4999 imposes an excise tax on the recipient of any excess parachute payment equal to 20 percent of that payment. A parachute payment is any payment in the nature of compensation to a disqualified individual (as defined under Section 280G of the Internal Revenue Code) if such payment is (a) contingent on a change in control and (b) the aggregate present value of the payments in the nature of compensation to such individual which are contingent on such change equals or exceeds an amount equal to three times the base amount (average compensation over the previous five-year period of employment). The term contingent on a change in control means not only that a payment would not have been made but for the change in control (a condition precedent), it also means a payment for which the timing of such payment is accelerated as a result of the change in control. The Company has also agreed to make payments to each of its expatriate employees equal to the effect of such excise tax if applicable to them.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Recent Developments

On October 13, 2005, we announced that we had entered into a merger agreement with Occidental Petroleum Corporation (Occidental) and Occidental Transaction 1, LLC, a wholly-owned subsidiary of Occidental. Upon completion of the merger, we will be merged with and into Occidental Transaction 1, LLC and our separate corporate existence will cease. According to this agreement, at the effective time of the merger, each outstanding share of our common stock (other than shares of our common stock owned by Occidental, Occidental Transaction 1, LLC and us and not held on behalf of third parties or any stockholders who are entitled to and who properly exercise appraisal rights under Delaware law) will be cancelled and converted into the right to receive 0.42 of a share of Occidental s common stock plus $20.00 in cash. All of our outstanding options and unvested stock awards will be fully vested and converted into the right to receive the fair market value in cash of the consideration described above, using a five-day average trading price of the Occidental common stock (ending on the last trading day before the effective time of the merger), and, in the case of an option, the amount will be reduced by the exercise price per share of the option.

There are several approvals and conditions required to complete the merger, but we have agreed with Occidental that we will both use our reasonable best efforts and, subject to certain limitations, take such actions as are required in connection with obtaining such approvals and satisfying such conditions. The merger agreement contains limited termination rights and, upon the termination of the agreement under specified circumstances, we may be required to pay Occidental a termination fee of $75,000,000. The agreement also includes other representations, warranties and covenants that are customary for transactions of this type.

We will file a proxy statement, Occidental will file a registration statement on Form S-4 and both of us will file other relevant documents concerning the proposed merger transaction with the SEC. We plan to complete the merger promptly after our stockholders approve and adopt the merger agreement at a special meeting and after the satisfaction or waiver of all other conditions to the merger. We currently expect this to occur shortly after the special meeting. However, there can be no assurance that the conditions to closing will be met or that the merger will be completed shortly after the special meeting.

The foregoing description of the merger and the merger agreement does not purport to be complete and is qualified in its entirety by reference to the merger agreement, which has been filed as Exhibit 2 to our Form 8-K filed on October 18, 2005. For additional information regarding the pending merger, refer to our current reports on Form 8-K, filed with the SEC on October 14 and October 18, 2005, and any subsequent current or periodic reports that we may file with the SEC in connection with the pending merger transaction. Please also refer to the proxy statement we will file and the Form S-4 registration statement Occidental will file in each case with the SEC in connection with the pending merger transaction.

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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 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 nine months of 2005, we spent an additional $70.1 million on acquisitions, primarily in the U.S., and subsequent to September 30, 2005, we made additional U.S. acquisitions of $26.4 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 $216.7 million of non-acquisition oil and gas capital expenditures in the first nine months of 2005 and we plan to spend a total of approximately $285 million in 2005, exclusive of acquisitions. We expect to have sufficient internally generated cash flows to fund our non-acquisition capital expenditures.

We reported net income of $72.2 million in the third quarter of 2005, representing a 164 percent increase over income from continuing operations of $27.4 million in the third quarter of 2004. Net income for the third quarter of 2004 was $27.0 million, including a loss from discontinued operations of $0.4 million. Our net income for the nine months ended September 30, 2005, was $161.9 million, compared to net income of $83.6 million for the nine months ended September 30, 2004. Net income for the first nine months of 2005 included $10.7 million of income from discontinued operations compared to $3.1 million of income from discontinued operations in the first nine months of 2004. Income from continuing operations for the first nine months of 2005 was significantly impacted by $41.0 million of losses related to 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 September 30, 2005, $21.6 million of these losses had been realized and $19.4 million remained unrealized. Net income for the first nine months of 2005 was reduced by $11.8 million ($19.4 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 nine 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 third quarter of 2005 of 6.8 MMBOE was five percent greater than the 6.4 MMBOE of production from continuing operations for the third quarter of 2004. Similarly, production from continuing operations for the nine months ended September 30, 2005, of 20.4 MMBOE was 14 percent greater than the 18.0 MMBOE of production from continuing operations for the nine months ended September 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 nine months ended September 30, 2005, was reduced by an estimated 179 MBOE as a result of the recent hurricanes in the Gulf of Mexico. We currently have approximately 950 net BOPD and 16.0 net MMcf per day of our production shut in as a result of these hurricanes. We expect most of the gas production to resume by the middle of November 2005. Also, our U.S. production for the first nine months of 2005 was further reduced by an estimated 279 MBOE as a result of heavy rains and mudslides in Ventura County, California earlier in the year, which required us to shut in certain wells. The shut-in wells in California have now been returned to production. Our Argentina production for the three months and nine months ended September 30, 2004, was negatively impacted by a contract oil field worker strike, which reduced production by an estimated 183 MBOE and 598 MBOE, respectively. Similarly, a contract oil field worker strike in the third quarter of 2005 reduced our Argentina production for the three months and nine months ended September 30, 2005, by 277 MBOE. The third quarter 2005 strike was resolved quickly and current production levels are above the pre-strike levels.

As a result of the 14 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 nine months of 2005 was $360.2 million, which was 63 percent higher than the first nine months of 2004. The increases in cash flow from increased production and higher prices were slightly offset by higher cash operating expenses.

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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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Production:				
Oil (MBbls) -				
U.S. (a)	1,640	1,555	4,831	4,600
Argentina (b)(c)	3,004	2,578	9,105	7,453
Bolivia (b)	14	24	44	65
Yemen (b)	474	107	1,177	166
Continuing operations	5,132	4,264	15,157	12,284
Canada		214		664
Total	5,132	4,478	15,157	12,948
Gas (MMcf) -				
U.S. (a)	6,512	8,135	21,336	21,500
Argentina (c)	1,947	2,306	6,328	6,485
Bolivia	1,278	2,466	3,845	6,014
Continuing operations	9,737	12,907	31,509	33,999
Canada		3,785		11,591
Total	9,737	16,692	31,509	45,590
MBOE from continuing operations	6,755	6,415	20,409	17,951
Total MBOE	6,755	7,260	20,409	20,546

(a) U.S. production for the three months and nine months ended September 30, 2005, is estimated to have been reduced as a result of hurricanes in the Gulf Coast by 56 MBbls of oil and 740 MMcf of gas, or 179 MBOE. In addition, U.S. production for the nine months ended September 30, 2005, is estimated to have been reduced as a result of mudslides in Ventura County, California by 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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Argentina	2,931	2,528	8,787	7,458
Bolivia	13	28	40	71
Yemen	431	174	1,166	282

(c) Argentina production for the three months and nine months ended September 30, 2004, is estimated to have been reduced as the result of a contract oil field worker strike by 162 MBbls of oil and 129 MMcf of gas, or 183 MBOE, and 527 MBbls of oil and 429 MMcf of gas, or 598 MBOE, respectively. Argentina production for the three months and nine months ended September 30, 2005, is estimated to have been reduced as the result of a contract oil field worker strike by 246 MBbls of oil and 188 MMcf of gas, or 277 MBOE.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Average Sales Price (including impact of hedges):				
Oil (per Bbl) -				
U.S. (a)	$ 40.04	$ 27.52	$ 37.91	$ 27.53
Argentina	40.06	34.39	35.11	31.27
Bolivia	25.22	24.68	23.61	24.42
Yemen	59.63	40.56	53.02	36.49
Continuing operations (a)	41.82	31.99	37.36	29.90
Canada		28.39		28.33
Gas (per Mcf) -				
U.S.	$ 7.46	$ 5.31	$ 6.67	$ 5.26
Argentina	1.00	0.74	0.90	0.64
Bolivia	2.29	1.72	1.95	1.66
Continuing operations	5.49	3.81	4.94	3.74
Canada		4.75		4.82
Average Sales Price (excluding impact of hedges):				
Oil (per Bbl) -				
U.S.	$ 56.07	$ 38.85	$ 48.14	$ 35.34
Argentina	40.06	34.39	35.11	31.27
Bolivia	25.22	24.68	23.61	24.42
Yemen	59.63	40.56	53.02	36.49
Continuing operations	46.94	36.12	40.62	32.82
Canada		37.10		33.85
Gas (per Mcf) -				
U.S.	$ 8.02	$ 5.27	$ 6.82	$ 5.27
Argentina	1.00	0.74	0.90	0.64
Bolivia	2.29	1.72	1.95	1.66
Continuing operations	5.86	3.78	5.04	3.74
Canada		4.75		4.82

(a) The average oil sales price per barrel for the U.S. does not reflect realized losses of $5.33 and $4.47 per barrel for the three months and nine months ended September 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 $1.70 and $1.42 per barrel for the three months and nine months ended September 30, 2005, respectively, which relate to settlements on economic hedges. 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 Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended, 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 and further influenced by the export tax, as discussed below. 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 31 percent increase in our average oil price from continuing operations, including the impact of hedging activities (30 percent excluding the impact of hedging activities), during the third quarter of 2005 compared to the third quarter of 2004. In the first nine months of 2005, we experienced a 25 percent increase in our average oil price from continuing operations, including the impact of hedging activities (24 percent excluding the impact of hedging activities), compared to the first nine months of 2004.

During late 2004 and continuing in the first nine 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 and third quarters 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., excluding the impact of hedging activities. 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. The adverse impact of this tax is partially offset by the Argentine income tax savings related to deducting the impact of the export tax.

We currently export approximately 34 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. Domestic sales values have been further reduced to values lower than export parity when the West Texas Intermediate price has exceeded $55.00.

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 September 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 $7.2 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 nine months of 2004, we participated in oil price swap agreements covering 4.4 million barrels of our oil production at a weighted average NYMEX reference price of $30.07 per barrel and during the first nine months of 2005, we participated in oil price swap agreements covering 3.8 million barrels of our oil production at a weighted average NYMEX reference price of $36.60 per barrel. We accounted for all of the oil price swaps during the first nine months of 2004 as cash flow hedges and we accounted for 2.4 million barrels for the first nine 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 nine months of 2005 was 32 percent higher than the same period in 2004, including the impact of hedging activities (35 percent higher excluding hedging activities). Our total average gas price for the third quarter of 2005, including the impact of hedging activities was 44 percent higher (55 percent higher excluding hedging activities) than the same period of 2004.

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During the first nine months of 2004, we participated in gas price swap agreements covering 3.1 million MMBtu of our gas production at a weighted average NYMEX reference price of $5.91 per MMBtu. During the first nine months of 2005, we participated in gas price swap agreements covering 3.5 million MMBtu of our gas production at a weighted average NYMEX reference price of $6.32 per MMBtu and gas price collar agreements covering 8.2 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 nine 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 $12.0 million and $18.6 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 $2.6 million and $4.1 million, respectively, based on gas production for the first nine months of 2005. 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
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
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
460,000	$6.00	$6.80
920,000	6.00	8.02
460,000	6.00	8.73
920,000	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 September 30, 2005, we would have been required to pay $126.2 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 nine months ended September 30, 2005, and 2004 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004

Fair value of contracts at beginning of period	$ (109,230)	$ (29,424)	$ (34,446)	$ (7,551)
Net realized losses on contracts settled	38,655	19,172	74,219	39,755
Net decrease in fair value of all open contracts	(55,610)	(62,238)	(165,958)	(104,694)
Fair value of contracts at end of period	$ (126,185)	$ (72,490)	$ (126,185)	$ (72,490)

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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. On 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 September 30, 2005, we have now realized $31.5 million of these previously recorded losses, $30.3 million of which was realized in the first nine months of 2005. However, since the losses were previously recorded as an expense, the realization of the $31.5 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 $29.2 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	
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

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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.***

	Three Months Ended September 30,			
	2005	2004	Variance	
Revenues:				
Oil, condensate and NGL sales	$ 214,623	$ 136,382	$ 78,241	57%
Gas sales	53,457	49,158	4,299	9%
Sulfur sales	702	234	468	200%
Gas marketing	13,313	17,897	(4,584)	-26%
Total revenues	$ 282,095	$ 203,671	$ 78,424	39%
Production:				
Oil, condensate and NGL volumes (MBbls)	5,132	4,264	868	20%
Gas volumes (MMcf)	9,737	12,907	(3,170)	-25%
Total production (MBOE)	6,755	6,415	340	5%
Average sales price (including impact of hedges):				
Oil, condensate and NGL (per Bbl)	$ 41.82	$ 31.99	$ 9.83	31%
Gas (per Mcf)	5.49	3.81	1.68	44%

	Nine Months Ended September 30,			
	2005	2004	Variance	
Revenues:				
Oil, condensate and NGL sales	$ 566,269	$ 367,320	$ 198,949	54%
Gas sales	155,509	127,284	28,225	22%
Sulfur sales	2,434	949	1,485	156%
Gas marketing	48,015	50,131	(2,116)	-4%
Total revenues	$ 772,227	$ 545,684	$ 226,543	42%
Production:				
Oil, condensate and NGL volumes (MBbls)	15,157	12,284	2,873	23%
Gas volumes (MMcf)	31,509	33,999	(2,490)	-7%
Total production (MBOE)	20,409	17,951	2,458	14%
Average sales price (including impact of hedges):				
Oil, condensate and NGL (per Bbl)	$ 37.36	$ 29.90	$ 7.46	25%
Gas (per Mcf)	4.94	3.74	1.20	32%

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Oil, condensate and NGL sales. The 31 percent increase in our average oil price from the third quarter of 2004 to the third quarter of 2005 resulted in a $41.9 million increase in our oil, condensate and NGL sales between the same periods. The remaining $36.3 million increase in oil, condensate and NGL sales from the third quarter of 2004 to the third quarter of 2005 was the result of a 20 percent increase in production between the same periods.

Similarly, oil, condensate and NGL sales increased by $107.3 million from the first nine months of 2004 to the first nine months of 2005 as a result of the 23 percent increase in production between the same periods. The remaining $91.6 million increase in oil, condensate and NGL sales from the first nine months of 2004 to the first nine months of 2005 was the result of a 25 percent increase in our average oil price between the same periods.

Our oil production in Argentina, before the impact of changes in inventories, for the third quarter of 2005 averaged 31,862 BOPD, representing a 16 percent increase over the 27,480 BOPD for the third quarter of 2004. Oil production from Argentina for the first nine months of 2005 averaged 33,353 BOPD compared to 27,199 BOPD for the first nine months of 2004, which is a 23 percent increase between these periods. The increases were the results of additional production from our drilling and workover programs and our acquisition of producing properties in the San Jorge basin in September 2004. Our Argentina production for the three months and nine months ended September 30, 2004, was negatively impacted by a contract oil field worker strike, which reduced production by an estimated 162 MBbls and 527 MBbls, respectively. Similarly, a contract oil field worker strike in the third quarter of 2005 reduced our Argentina production for the three months and nine months ended September 30, 2005, by 246 MBbls. The third quarter 2005 strike was resolved quickly and current production levels are above the pre-strike levels.

Oil production from our An Nagyah field in Yemen began making a contribution in the second quarter of 2004. Our Yemen oil production was 107 MBbls for the third quarter of 2004 and 166 MBbls for first nine months of 2004. This compares to our Yemen oil production of 474 MBbls for the third quarter of 2005 and 1,177 MBbls for the first nine 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. An Nagyah production for the third quarter of 2005 was 4,685 net BOPD and we expect fourth quarter 2005 production to average approximately 5,450 net BOPD.

Our U.S. oil production increased by five percent from 16,901 BOPD in the third quarter of 2004 to 17,824 BOPD in the third quarter of 2005 and increased by five percent from 16,787 BOPD in the first nine months of 2004 to 17,694 BOPD in the first nine 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 third quarter of 2005 was reduced by 56 MBbls as a result of the recent hurricanes in the Gulf Coast. We currently have approximately 950 net BOPD per day of our production shut-in as a result of these hurricanes. Also, U.S. oil production for the nine months ended September 30, 2005, was reduced by an estimated 228 MBbls as a result of heavy rains and mudslides in Ventura County, California, which required us to shut in certain wells. These shut-in wells in California have now been returned to production.

Gas sales. The increase in gas sales from the third quarter of 2004 to the third quarter of 2005 was the result of the 44 percent increase in our average gas price between the same periods. The $21.7 million increase in gas sales from the price increase was reduced by $17.4 million resulting from a 25 percent decline in our gas production from the third quarter of 2004 to the third quarter of 2005.

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Similarly, the increase in gas sales from the first nine months of 2004 to the first nine months of 2005 was the result of the 32 percent increase in our average gas price between the same periods. The $40.5 million increase in gas sales from the price increase was reduced by $12.3 million resulting from a seven percent decline in our gas production from the first nine months of 2004 to the first nine months of 2005.

Anticipated lower sales volumes in the domestic market and into Brazil caused Bolivia gas production to decrease by 48 percent, or 1,188 MMcf (12,920 Mcf per day) from the third quarter of 2004 to the third quarter of 2005, and decrease by 36 percent, or 2,169 MMcf (7,947 Mcf per day) from the first nine months of 2004 to the first nine months of 2005.

Our successful exploitation program in the U.S. and our December 2004 acquisition of producing properties in Alabama led to gas production increases, but these increases were offset by anticipated natural production declines in certain U.S. fields and production shut in due to weather-related problems. We estimate that U.S. gas production for the third quarter of 2005 was reduced by 740 MMcf (8,043 Mcf per day) as a result of the recent hurricanes in the Gulf Coast. As a result of damage from the hurricanes, we currently have approximately 16,000 net Mcf per day shut-in, most of which is expected to be returned to production by the middle of November 2005. In addition, we estimate that our U.S. gas production was reduced by 304 MMcf for the first nine months of 2005 as a result of the California rain and mudslides discussed previously. These shut-in wells in California have now been returned to production.

Our Argentina production for the three months and nine months ended September 30, 2004, was negatively impacted by an estimated 129 MMcf and 429 MMcf, respectively, and our Argentina production for the three months and nine months ended September 30, 2005, was reduced by 188 MMcf as a result of the contract oil field worker strikes discussed previously.

Sulfur sales. The increases in sulfur sales between the third quarter of 2004 and the third quarter of 2005 and between the first nine months of 2004 and the first nine months of 2005 were primarily the result of increases in sulfur volumes produced. The volume increases relate to the purchase of certain properties in Alabama in December 2004.

Gas marketing revenues. Gas marketing revenues decreased from the third quarter of 2004 to the third quarter of 2005 primarily as a result of a decrease in third-party gas volumes we marketed. Almost all of these third-party gas volumes come from the U.S. fields which we operate. The decrease in gas volumes in the third quarter of 2005 resulted from the hurricanes in the Gulf Coast and the anticipated natural production declines discussed above. Gas marketing revenues for the nine months ended September 30, 2005, also suffered from these decreases in third-party gas volumes, resulting in a decline from the nine months ended September 30, 2004.

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	Three Months Ended September 30, 2005	2004	Variance	
Costs and expenses:				
Production costs	$ 46,669	$ 34,010	$ 12,659	37%
Transportation and storage costs	4,163	3,643	520	14%
Production and ad valorem taxes	9,738	5,732	4,006	70%
Export taxes	19,155	12,778	6,377	50%
Exploration costs	12,432	12,435	(3)	
Gas marketing	12,307	16,857	(4,550)	-27%
General and administrative	17,807	13,959	3,848	28%
Depreciation, depletion and amortization	35,914	26,720	9,194	34%
Accretion	1,819	1,685	134	8%
Other operating expenses	549	1,671	(1,122)	-67%
Total costs and expenses	$ 160,553	$ 129,490	$ 31,063	24%
Costs and expenses per BOE:				
Production costs	$ 6.91	$ 5.30	$ 1.61	30%
Transportation and storage costs	0.62	0.57	0.05	9%
General and administrative	2.64	2.18	0.46	21%
Depreciation, depletion and amortization	5.32	4.17	1.15	28%

	Nine Months Ended September 30, 2005	2004	Variance	
Costs and expenses:				
Production costs	$ 133,864	$ 104,175	$ 29,689	28%
Transportation and storage costs	12,692	8,704	3,988	46%
Production and ad valorem taxes	24,954	16,557	8,397	51%
Export taxes	48,823	25,691	23,132	90%
Exploration costs	30,187	21,000	9,187	44%
Gas marketing	44,973	47,409	(2,436)	-5%
General and administrative	51,978	48,814	3,164	6%
Depreciation, depletion and amortization	103,664	72,687	30,977	43%
Impairment of proved oil and gas properties		3,915	(3,915)	n/a
Accretion	5,358	4,932	426	9%
Other operating (income) expenses	3,478	(1,933)	5,411	-280%
Total costs and expenses	$ 459,971	$ 351,951	$ 108,020	31%
Costs and expenses per BOE:				
Production costs	$ 6.56	$ 5.80	$ 0.76	13%
Transportation and storage costs	0.62	0.48	0.14	29%
General and administrative	2.55	2.72	(0.17)	-6%
Depreciation, depletion and amortization	5.08	4.05	1.03	25%

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Production costs. Production costs per BOE increased from the third quarter of 2004 to the third quarter of 2005 and from the first nine months of 2004 to the first nine months of 2005. Higher labor costs in Argentina and increased lease power and fuel costs in the U.S. contributed to this increase. In addition to these increases, during the three months and nine months ended September 30, 2005, we incurred approximately $0.9 million ($0.13 per BOE) and $6.6 million ($0.32 per BOE), respectively, to repair damage from the heavy rains and mudslides in California. Production costs for the first nine months of 2004 included $3.1 million ($0.17 per BOE) for costs to repair damage resulting from fires in California during late 2003.

Approximately $1.8 million of the increase in our production costs between the third quarter of 2004 and the third quarter of 2005 relates to the five percent increase in our total production on a BOE basis between the same periods. Similarly, approximately $14.3 million of the increase in our production costs between the first nine months of 2004 and the first nine months of 2005 relate to the 14 percent increase in our total production on a BOE basis between the same periods.

Transportation and storage costs. The increases between the third quarter of 2004 and the third quarter of 2005 and between the first nine months of 2004 and the first nine 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 have 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 is expected to reduce our transportation cost per barrel in Yemen in future periods.

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 third quarter of 2004 and the third quarter of 2005 and between the first nine months of 2004 and the first nine months of 2005. In addition, the Bolivian production tax established in 2005 resulted in additional production taxes of $1.3 million for the third quarter of 2005 and $1.7 million for the first nine months of 2005.

Export taxes. The increases in Argentine export taxes between the third quarter of 2004 and the third quarter of 2005 and between the first nine months of 2004 and the first nine 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 third quarter of 2005 on our exported volumes was 31.0 percent.

Exploration costs. Exploration costs of $12.4 million for the third quarter of 2005 related primarily to unsuccessful exploratory drilling in Yemen. During the third quarter of 2004, our exploration costs were comprised of $1.4 million for seismic and other geological and geophysical costs, $9.9 million for unsuccessful exploratory drilling, primarily in the U.S. and Yemen, and $1.1 million for impairments of unproved leasehold costs, primarily in the U.S.

Exploration costs for the first nine months of 2005 consisted of $9.3 million for seismic and other geological and geophysical costs, $19.2 million for unsuccessful exploratory drilling, primarily in Yemen, and $1.7 million for impairments of unproved leasehold costs. During the first nine months of 2004, our exploration costs were comprised of $4.3 million for seismic and other geological and geophysical costs, $14.2 million for unsuccessful exploratory drilling and $2.5 million for impairments of unproved leasehold costs.

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Gas marketing expenses. Gas marketing expenses represent our purchase cost for third-party gas that we market. Our gas marketing purchases and sales directly affect each other. As discussed above in relation to gas marketing revenues, the decrease from the third quarter of 2004 to the third quarter of 2005, and to a lesser extent the decrease from the first nine months of 2004 to the first nine months of 2005, primarily resulted from decreased third-party gas volumes we marketed.

General and administrative expense. The increases in general and administrative expenses from the third quarter of 2004 to the third quarter of 2005 and from the first nine months of 2004 to the first nine months of 2005 relate to higher bonus accruals and higher stock compensation expense.

On October 13, 2005, in light of our pending merger and our performance through September 30, 2005, and projected performance for the fourth quarter of 2005, our Board of Directors, upon the recommendation of its Compensation Committee, granted bonuses for 2005 to our eligible U.S. employees, including executive officers. We recorded additional bonus expense in September 2005, and will record additional bonus expense in the fourth quarter of 2005 to reflect the actual amount of the 2005 bonuses granted.

Depreciation, depletion and amortization. Approximately $7.8 million of the increase in our depreciation, depletion and amortization expense from the third quarter of 2004 to the third quarter of 2005 relates to the 28 percent increase in our amortization rate per BOE between the same periods and the remaining $1.4 million of the increase relates to the five percent increase in our production on a BOE basis between the periods. Approximately $21.0 million of the increase in our depreciation, depletion and amortization expense from the first nine months of 2004 to the first nine months of 2005 relates to the 25 percent increase in our amortization rate per BOE between the same periods and the remaining $10.0 million of the increase relates to the 14 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, in the Gulf Coast area of Alabama in December 2004 and our U.S. acquisitions in 2005, and the impact of increased production on certain U.S. fields and in Yemen, which all 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 or third quarters of 2004 or in the first nine 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 or third quarters of 2004 or in the first nine months of 2005.

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	Three Months Ended September 30,			
	2005	2004	Variance	
Non-operating (income) expense:				
Interest expense	$ 11,467	$ 12,625	$ (1,158)	-9%
(Gain) loss on derivative transactions	(1,420)	14,917	(16,337)	-110%
Gain on disposition of assets	(925)	(17)	(908)	5341%
Foreign currency exchange gain	(676)	(285)	(391)	137%
Other non-operating (income) expense	(1,467)	804	(2,271)	-282%
Net non-operating expense	$ 6,979	$ 28,044	$ (21,065)	-75%

	Nine Months Ended September 30,			
	2005	2004	Variance	
Non-operating (income) expense:				
Interest expense	$ 34,622	$ 39,321	$ (4,699)	-12%
Loss on early extinguishment of debt		9,903	(9,903)	n/a
Loss on derivative transactions	42,024	15,361	26,663	174%
Gain on disposition of assets	(941)	(72)	(869)	1207%
Foreign currency exchange (gain) loss	1,659	(1,112)	2,771	-249%
Other non-operating (income) expense	(2,624)	630	(3,254)	-517%
Net non-operating expense	$ 74,740	$ 64,031	$ 10,709	17%

Interest expense. Interest expense decreased between the third quarter of 2004 and the third quarter of 2005 due to a 21 percent reduction in our average debt outstanding and decreased between the first nine months of 2004 and the first nine months of 2005 due to a similar 21 percent reduction in our average debt outstanding. 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 a call premium 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 third quarter of 2004 or in the first nine months of 2005.

Gains and losses on derivative transactions. We recorded losses on derivative transactions of $14.4 million in the third quarter of 2004 and $41.0 million in the first quarter of 2005 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 or second quarters of 2004 or in the second or third quarters of 2005. We also recorded gains and losses from the ineffective portion of our hedges resulting in a $1.4 million gain and a $0.5 million loss for the third quarters of 2005 and 2004, respectively, and a $1.0 million loss and a $0.9 million loss for the nine months ended September 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. On March 1, 2005, we determined that the correlation indicated that our existing oil price swap agreements were again 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 third quarter of 2004, the Argentina peso weakened slightly against the U.S. dollar with the peso-to-dollar exchange rate increasing from 2.97 to 2.98 from June 30, 2004, to September 30, 2004, resulting in a $0.3 million gain. In the third quarter of 2005, the peso weakened slightly against the dollar with an exchange rate of 2.90 at June 30, 2005, compared to 2.92 at September 30, 2005, resulting in a $0.7 million gain.

In the first nine months of 2004, the peso weakened against the dollar with the exchange rate of 2.94 at December 31, 2003, compared to 2.98 at September 30, 2004, resulting in a $1.0 million gain. In the first nine months of 2005, the peso strengthened against the dollar with an exchange rate of 2.98 at December 31, 2004, compared to 2.92 at September 30, 2005, resulting in a $1.9 million loss.

Other non-operating income. Due to the significant cash balances that we maintained in 2005, we recorded interest income of $1.6 million in the third quarter of 2005 and $2.6 million in the nine months ended September 30, 2005. We had only minimal interest income in 2004.

Cash Flows

Our primary source of cash during the first nine 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 $56.4 million. See below for additional discussion of our cash flows from operating activities.

	Nine Months Ended September 30,		
	2005	**2004**	**Change**
Cash provided (used) by (in thousands):			
Operating activities - continuing operations	$ 360,221	$ 221,568	$ 138,653
Operating activities - discontinued operations		34,646	(34,646)
Investing activities - continuing operations	(308,326)	(185,906)	(122,420)

Investing activities - discontinued operations		(23,785)	23,785
Financing activities	4,858	(33,407)	38,265

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Cash provided by continuing operations increased 63 percent to $360.2 million in the first nine months of 2005 compared to $221.6 million in the first nine months of 2004. Increases in production from continuing operations and higher product prices for the first nine 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 $20.1 million of cash provided by changes in working capital for the first nine months of 2005 compared to $6.1 million of cash provided by changes in working capital for the first nine months of 2004. See Results of Operations and Period to Period Comparison for further discussion.

Investing activities in the first nine months of 2005 included capital spending of $281.8 million on a cash basis, or 78 percent of cash provided by continuing operations. This compares to capital spending in the first nine months of 2004 of $161.7 million, or 73 percent of cash provided by continuing operations. Cash used by investing activities in the first nine months of 2005 also includes $21.6 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 nine 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 nine months of 2005 were as follows (in thousands):

	U.S.	Argentina	Bolivia	Yemen	Other	Total
Acquisitions:						
Unproved properties	$ 17,770	$	$	$	$	$ 17,770
Proved properties	68,747	1,389				70,136
Exploratory	13,061	581		7,794	193	21,629
Development	59,010	96,206		22,100		177,316
	$ 158,588	$ 98,176	$	$ 29,894	$ 193	$ 286,851

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

U.S.:	
Unproved leasehold costs	$ 24,993
Unevaluated exploratory drilling	7,554
	32,547
Yemen:	
Unproved leasehold costs	2,500
Unevaluated exploratory drilling	158

	2,658
	$ 35,205

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.

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. Our 2005 capital expenditure budget is $285 million, exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. In the fourth quarter of 2005, we anticipate spending approximately $57 million on development activities, primarily in the U.S. and Argentina, and approximately $11 million in exploration activities. A portion of our planned spending on conventional and unconventional resource exploration in the U.S. has been deferred due to the lengthy process of maturing prospects and difficulty obtaining drilling rigs on a timely basis.

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.

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 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 September 30, 2005, we had unused availability under our revolving credit facility of $295.3 million (considering outstanding letters of credit of approximately $4.7 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 nine months of 2005 were 25 percent and 32 percent higher, respectively, compared to the first nine months of 2004. These prices have historically fluctuated widely in response to changing market forces. For the first nine months of 2005, approximately 74 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.

We have agreed in our merger agreement with Occidental that, among other things, we will not engage in certain kinds of transactions during the interim period between the execution of the agreement and the consummation of the merger, including limitations on our ability to incur debt, issue securities and sell or acquire material assets. If we were to seek to engage in a restricted activity under these covenants, we would be required to obtain the prior consent of Occidental. Based on current commodity prices and current capital projects, we do not anticipate that these contractual limitations will materially adversely affect our ability to satisfy our liquidity needs during this interim period and we expect that cash generated from operating activities and cash on hand will be sufficient for the remainder of 2005 to cover our operating and capital spending requirements and to make expected dividend payments. In addition, we believe that our available borrowing capacity is sufficient to enable us to meet unanticipated cash requirements, if needed.

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Contractual Obligations

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

Income Taxes

We incurred a current provision for income taxes from continuing operations of approximately $79.9 million and $44.1 million for the first nine 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, after-tax income considered to be permanently reinvested in certain foreign subsidiaries totaled approximately $155 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 nine months ended September 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 nine months ended September 30, 2005.

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

	Nine Months Ended September 30,	
	2005	**2004**
U.S. federal statutory income tax rate	35.0%	35.0%
U.S. state income tax (net of federal tax benefit)	1.0	
U.S. permanent differences	(2.1)	0.7
Foreign operations	2.5	2.3
	36.4%	38.0%

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.

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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 associated interpretive guidance. No regulations from either Congress or the Treasury Department have been issued. At the current date, we have not determined if 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 above, 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 intended to identify forward-looking statements.

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

- the proposed merger with Occidental;
- 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;
- a delay in or the failure to obtain required approvals and failure to satisfy conditions to closing the proposed merger;
- 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;

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 September 30, 2005, all of our outstanding debt was at fixed rates. Because we had no outstanding borrowings under variable-rate debt instruments as of September 30, 2005, a change in the average interest rate of 100 basis points would result in no change in our net income 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:

	2005	2006	2007	2008	2009	There-after	Total	Fair Value at 9/30/05
Long-Term Debt:								
Fixed rate (in thousands)						$ 549,953	$ 549,953	$ 583,500
Average interest rate						8.1%	8.1%	
Variable rate (in thousands)								
Average interest rate								

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 nine months of 2005, our operations in Argentina accounted for approximately 42 percent of our revenues and 37 percent of our total assets. During the first nine 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.

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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, work stoppages, 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 maintain political risk insurance.

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 September 30, 2005, was 2.92 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.

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

	Peso Balance	U.S. Dollar Equivalent
Current assets	5,073	$ 1,740
Current liabilities	(145,048)	(49,759)
Non-current liabilities	(71,134)	(24,403)
Net monetary liabilities	(211,109)	$ (72,422)

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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. The export tax is deducted for income tax purposes but is not deducted in the calculation of royalty payments.

We currently export approximately 34 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. Domestic sales values have been further reduced to values lower than export parity when the West Texas Intermediate price has exceeded $55.00.

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, and September 1, 2005, we received letters 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 September 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 $7.2 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 nine 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.

During September 2005, a new union targeting personnel with supervisory responsibility (the Supervisors Union) achieved legal status in the provinces of Chubut, Santa Cruz and Tierra del Fuego. The Supervisors Union caused a work stoppage in October 2005, demanding wage increases for their members in the above referenced provinces. The National Ministry of Labor ordered a mandatory conciliation process to discuss the unions demand and negotiations are currently being held. We estimate that approximately 20 percent of our field employees belong to this union.

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.

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.

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In September 2005, the Constitutional Tribunal ruled in favor of reallocating regional seats in the lower house of congress in accordance to the census taken in 2001. This reallocation was required to take place prior to the national elections, which were scheduled for December 4, 2005. The National Electoral Court established a deadline of October 28, 2005, for congress to approve the electoral reforms so that those reforms could be effectively implemented prior to the elections. Congress failed to approve an article to reform the electoral law by that date. The National Electoral Court indefinitely suspended the presidential and general elections from the scheduled date of December 4, 2005. On November 1, 2005, President Eduardo Rodriguez issued presidential decree number 28429, creating a political compromise in the reallocation of regional seats, which established a legal basis for elections to be held on December 18, 2005.

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.

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 27967, 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 three months of 2005 and in 2006, we have contracted volumes of 0.3 Bcf and 0.8 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 42 MMcf of gas, gross, and 26 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 September 30, 2005, was 8.08 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.

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.

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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 September 30, 2005, was 193.3 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 not to 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 September 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

Not applicable

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.

2.1	Agreement and Plan of Merger dated as of October 13, 2005, by and among Vintage Petroleum, Inc., Occidental Petroleum Corporation and Occidental Transaction 1, LLC. (filed as Exhibit 2 to our Current Report on Form 8-K dated October 18, 2005).
4.1	Second Amendment to Rights Agreement dated as of October 13, 2005, by and between Vintage Petroleum, Inc. and Mellon Investor Services LLC (filed as Exhibit 4 to our Amendment No. 2 to Registration Statement on Form 8-A/A, dated October 17, 2005).
10.1	Form of Amendment to Restricted Stock Rights Award Agreement(s).
10.2	Summary of Vintage Petroleum, Inc. Completion Bonus Program.
10.3	

	Summary of Amendment to Vintage Petroleum, Inc. Performance-Based Cash Bonus Program for Chief Executive Officer.
10.4	Summary of Vintage Petroleum, Inc. Agreement to Make Gross-Up Payments for Internal Revenue Code Section 4999 Excise Taxes.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes-Oxley Act of 2002.

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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: November 7, 2005

/s/ MICHAEL F. MEIMERSTORF
Michael F. Meimerstorf

Vice President and Controller

(Principal Accounting Officer)

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Exhibit Index

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.

Exhibit Number	Description
2.1	Agreement and Plan of Merger dated as of October 13, 2005, by and among Vintage Petroleum, Inc., Occidental Petroleum Corporation and Occidental Transaction 1, LLC. (filed as Exhibit 2 to our Current Report on Form 8-K dated October 18, 2005).
4.1	Second Amendment to Rights Agreement dated as of October 13, 2005, by and between Vintage Petroleum, Inc. and Mellon Investor Services LLC (filed as Exhibit 4 to our Amendment No. 2 to Registration Statement on Form 8-A/A, dated October 17, 2005).
10.1	Form of Amendment to Restricted Stock Rights Award Agreement(s).
10.2	Summary of Vintage Petroleum, Inc. Completion Bonus Program.
10.3	Summary of Amendment to Vintage Petroleum, Inc. Performance-Based Cash Bonus Program for Chief Executive Officer.
10.4	Summary of Vintage Petroleum, Inc. Agreement to Make Gross-Up Payments for Internal Revenue Code Section 4999 Excise Taxes.
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.