CONCHO RESOURCES INC
Form 10-Q
August 13, 2008

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended June 30, 2008

or

o **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: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0818600**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
550 West Texas Avenue, Suite 1300 Midland, Texas	**79701**
(Address of principal executive offices)	(Zip code)

(432) 683-7443

(Registrant s telephone number, including area code)

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 þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer þ (Do not check if a smaller reporting company)	Smaller reporting company o

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

Number of shares of the registrant s common stock outstanding at August 12, 2008: 84,432,912 shares.

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PART I FINANCIAL INFORMATION

Item 1. CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

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Concho Resources Inc. and subsidiaries
Consolidated balance sheets
Unaudited

(in thousands, except share and per share data)	June 30, 2008	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 31,716	$ 30,424
Accounts receivable:		
Oil and gas, net of allowance for doubtful accounts	55,270	36,735
Joint operations and other	10,903	21,183
Assets held for sale		256
Derivative instruments		1,866
Deferred income taxes	44,750	13,502
Prepaid insurance and other	3,224	4,017
Total current assets	145,863	107,983
Property and equipment, at cost:		
Oil and gas properties, successful efforts method	1,675,163	1,555,018
Accumulated depletion and depreciation	(209,688)	(167,109)
Total oil and gas properties, net	1,465,475	1,387,909
Other property and equipment, net	10,046	7,085
Total property and equipment, net	1,475,521	1,394,994
Deferred loan costs, net	3,800	3,426
Inventory	8,702	1,459
Other assets	347	367
Total assets	$ 1,634,233	$ 1,508,229
Liabilities and stockholders equity		
Current liabilities:		
Accounts payable:		
Trade	$ 5,509	$ 14,222
Related parties	623	2,119
Other current liabilities:		
Bank overdrafts	8,896	5,651
Revenue payable	22,212	14,494
Accrued drilling costs	34,955	39,276
Accrued interest	496	1,590
Other accrued liabilities	18,291	11,935
Derivative instruments	114,504	36,414
Income taxes payable		29
Current portion of long-term debt	2,500	2,000

Current asset retirement obligations	765	912
Total current liabilities	208,751	128,642
Long-term debt	298,453	325,404
Noncurrent derivative instruments	44,824	10,517
Deferred income taxes	288,098	259,070
Asset retirement obligations and other long-term liabilities	10,148	9,198
Commitments and contingencies (Note K)		
Stockholders equity:		
Preferred stock, $0.001 par value; 10,000,000 shares authorized; and zero shares issued and outstanding at June 30, 2008 and December 31, 2007		
Common stock, $0.001 par value; 300,000,000 authorized; 76,140,269 and 75,832,310 shares issued at June 30, 2008 and December 31, 2007, respectively	76	76
Additional paid-in capital	759,928	752,380
Notes receivable from employees		(330)
Retained earnings	45,412	37,467
Accumulated other comprehensive income (loss)	(21,332)	(14,195)
Treasury stock, at cost; 3,142 and zero shares of common stock at June 30, 2008 and December 31, 2007, respectively	(125)	
Total stockholders equity	783,959	775,398
Total liabilities and stockholders equity	$1,634,233	$1,508,229

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc. and subsidiaries
Consolidated statements of operations
Unaudited

	Three months ended June 30,		Six months ended June 30,	
(in thousands, except per share amounts)	**2008**	**2007**	**2008**	**2007**
Operating revenues:				
Oil sales	$ 95,408	$ 43,096	$171,226	$ 82,467
Natural gas sales	41,975	23,007	72,868	43,982
Total operating revenues	137,383	66,103	244,094	126,449
Operating costs and expenses:				
Oil and gas production	9,949	6,950	17,766	14,209
Oil and gas production taxes	12,030	5,256	21,108	9,943
Exploration and abandonments	723	5,864	3,464	6,305
Depreciation and depletion	22,010	17,609	43,294	37,033
Accretion of discount on asset retirement obligations	148	115	301	228
Impairments of proved oil and gas properties	53	2,085	69	3,198
Contract drilling fees stacked rigs		915		4,269
General and administrative (including non-cash stock-based compensation of $1,730 and $1,128 for the three months ended June 30, 2008 and 2007, respectively, and $3,029 and $1,954 for the six months ended June 30, 2008 and 2007, respectively)	8,586	7,629	16,266	11,921
Bad debt expense	1,799		1,799	
Ineffective portion of cash flow hedges	(356)	(99)	(920)	1,156
Loss on derivatives not designated as hedges	102,456		119,634	
Total operating costs and expenses	157,398	46,324	222,781	88,262
Income (loss) from operations	(20,015)	19,779	21,313	38,187
Other income (expense):				
Interest expense	(3,885)	(10,074)	(9,500)	(20,749)
Other, net	311	208	1,331	473
Total other expense	(3,574)	(9,866)	(8,169)	(20,276)
Income (loss) before income taxes	(23,589)	9,913	13,144	17,911
Income tax benefit (expense)	9,169	(3,988)	(5,199)	(7,363)
Net income (loss)	(14,420)	5,925	7,945	10,548
Preferred stock dividends		(11)		(45)
Net income (loss) applicable to common shareholders	$ (14,420)	$ 5,914	$ 7,945	$ 10,503

Basic earnings (loss) per share:				
Net income (loss) per share	$ (0.19)	$ 0.10	$ 0.11	$ 0.19
Weighted average shares used in basic earnings (loss) per share	75,665	57,747	75,569	56,369
Diluted earnings (loss) per share:				
Net income (loss) per share	$ (0.19)	$ 0.10	$ 0.10	$ 0.18
Weighted average shares used in diluted earnings (loss) per share	75,665	59,625	77,034	59,260

The accompanying notes are an integral part of these consolidated financial statements.

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Concho Resources Inc. and subsidiaries
Consolidated statements of stockholders equity
Unaudited

(in thousands)	Common stock Shares	Common stock Amount	Additional paid-in capital	Notes receivable from officers and employees	Retained earnings	Accumulated other comprehensive income (loss)	Treasury stock Shares	Treasury stock Amount	Total stockholders equity
BALANCE AT DECEMBER 31, 2007	75,832	$ 76	$ 752,380	$ (330)	$ 37,467	$ (14,195)		$	$ 775,398
Comprehensive income									
Net income					7,945				7,945
Deferred hedge losses, net of tax benefit of $12,705						(19,805)			(19,805)
Net settlement losses included in earnings, net of tax benefit of $8,127						12,668			12,668
Total comprehensive income									808
Stock options exercised	263		2,373						2,373
Restricted stock issued as stock-based compensation	81		862						862
Cancellation of restricted stock	(36)								
Stock-based compensation for stock options			2,167						2,167
Tax benefits related to stock-based compensation			2,146						2,146
Proceeds from notes receivable officers and employees				333					333
				(3)					(3)

Accrued interest employee notes									
Purchase of treasury stock							3	(125)	(125)
BALANCE AT JUNE 30, 2008	76,140	$ 76	$ 759,928	$	$ 45,412	$ (21,332)	3	$ (125)	$ 783,959

The accompanying notes are an integral part of these consolidated financial statements.

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Concho Resources Inc. and subsidiaries
Consolidated statements of cash flows
Unaudited

(in thousands)	Six months ended June 30, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 7,945	$ 10,548
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and depletion	43,294	37,033
Impairments of proved oil and gas properties	69	3,198
Accretion of discount on asset retirement obligations	301	228
Exploration expense, including dry holes	1,147	5,665
Non-cash compensation expense	3,029	1,954
Bad debt expense	1,799	
Gas imbalances	(137)	54
Deferred rent liability	22	41
Deferred income taxes	4,504	7,399
Interest accrued on employee notes	(3)	(240)
Amortization of deferred loan costs	627	1,889
Amortization of discount on long-term debt	49	40
Gain on sale of property and equipment	(777)	
Ineffective portion of cash flow hedges	(920)	1,156
Loss on derivatives not designated as hedges	119,634	
Dedesignated cash flow hedges reclassified from AOCI	222	
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	(12,003)	10,640
Prepaid insurance and other	793	3,985
Inventory	(7,243)	(5,000)
Excess tax benefit from stock-based compensation	(2,146)	
Accounts payable	(10,209)	(14,902)
Revenue payable	7,718	(404)
Accrued liabilities	6,356	(519)
Accrued interest	(1,094)	829
Income taxes payable	(29)	
Net cash provided by operating activities	162,948	63,594
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and gas properties	(122,757)	(69,889)
Acquisition of oil and gas properties and other assets		(256)
Additions to other property and equipment	(4,017)	(1,114)
Proceeds from the sale of oil and gas properties	1,034	652
Settlements paid on derivatives not designated as hedges	(16,387)	
Net cash used in investing activities	(142,127)	(70,607)

CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt	13,000	266,100
Payments of long-term debt	(39,500)	(257,600)
Exercise of incentive plan stock options	2,373	
Excess tax benefit from stock-based compensation	2,146	
Payments of preferred stock dividends		(132)
Proceeds from repayment of officer and employee notes	333	10,482
Payments for loan origination costs	(1,001)	(2,572)
Purchase of treasury stock	(125)	
Bank overdrafts	3,245	
Net cash provided by (used in) financing activities	(19,529)	16,278
Net increase in cash and cash equivalents	1,292	9,265
BEGINNING CASH AND CASH EQUIVALENTS	30,424	1,122
ENDING CASH AND CASH EQUIVALENTS	$ 31,716	$ 10,387
SUPPLEMENTAL CASH FLOWS:		
Cash paid for interest and fees, net of $840 and $1,336 capitalized interest	$ 9,918	$ 18,891
Cash paid for income taxes	$ 650	$ 1,800
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Issuance of common stock in acquisition of oil and gas properties and other assets	$	$ 650

The accompanying notes are an integral part of these consolidated financial statements.

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Concho Resources Inc. and subsidiaries
Condensed notes to consolidated financial statements
Unaudited

Note A. ***Organization and nature of operations***

Concho Resources Inc. (Resources) is a Delaware corporation formed by Concho Equity Holdings Corp. (CEHC) on February 22, 2006, for purposes of effecting the combination of CEHC, Chase Oil Corporation, Caza Energy LLC (Caza) and certain other parties thereto (collectively with Chase Oil Corporation and Caza, the Chase Group). Pursuant to the Combination Agreement dated February 24, 2006, Resources acquired working interests in oil and natural gas properties in Southeast New Mexico from the Chase Group (Chase Group Properties) and issued shares of its common stock to certain stockholders of CEHC in exchange for their capital stock of CEHC. CEHC is a Delaware corporation formed on April 21, 2004 by certain members of the Company s management team and private equity investors. CEHC commenced substantial oil and gas operations in December 2004 upon its acquisition of certain oil and gas properties located in Southeast New Mexico and West Texas. The combination transaction described above (the Combination) was accounted for as an acquisition by CEHC of the Chase Group Properties and a simultaneous reorganization of Resources such that CEHC is now a wholly owned subsidiary of Resources. Prior to the Combination, Resources had no assets, operations or net equity. Upon the closing of the Combination, the executive officers of CEHC became the executive officers of Resources. Resources and its wholly owned subsidiaries are collectively referred to herein as the Company.

CEHC s shareholders received 23,767,691 shares of common stock of Resources in exchange for their preferred and common shares of CEHC, excluding eighteen holders owning an aggregate of 254,621 shares of CEHC 6% Series A Preferred Stock and 127,313 shares of CEHC common stock, as discussed in Note G *Stockholders equity and stock issued subject to limited recourse notes*. In addition, the Chase Group transferred the Chase Group Properties to Resources in exchange for cash in the aggregate amount of approximately $409 million and 34,794,638 shares of Resources common stock. In connection with the Company s initial public offering and secondary public offering (both described below), the Chase Group sold a total of 18,638,014 shares of common stock thereby reducing its ownership interest. As of June 30, 2008 and December 31, 2007, the Chase Group owned approximately 12 percent and 21 percent, respectively, of the total outstanding common stock of the Company.

The Company s principal business is the acquisition, development, exploitation and exploration of oil and gas properties in the Permian Basin region of Southeast New Mexico and West Texas.

Initial public offering. On August 7, 2007, the Company completed an initial public offering (the IPO) of its common stock. The Company sold 13,332,851 shares of its common stock in the IPO and certain shareholders, including its executive officers and members of the Chase Group, sold 7,554,256 shares of Resources common stock, in each case, at $11.50 per share. After deducting underwriting discounts of approximately $9.6 million and offering expenses of approximately $4.5 million, the Company received net proceeds of approximately $139.2 million. In conjunction with the IPO, the underwriters were granted an option to purchase 3,133,066 additional shares of Resources common stock. The underwriters fully exercised this option and purchased the additional shares on August 9, 2007. After deducting underwriting discounts of approximately $2.2 million, the Company received net proceeds of approximately $33.8 million. The aggregate net proceeds of approximately $173.0 million received by the Company at closing on August 7, 2007 and August 9, 2007 were utilized in equal amounts to repay a portion of its term loan facility on August 9, 2007, and to prepay a portion of its revolving credit facility on August 20, 2007. See further discussion in Note J *Long-term debt.*

Secondary public offering. On December 19, 2007, the Company completed a secondary public offering of 11,845,000 shares of its common stock, which were sold by certain of its stockholders, including members of the Chase group. The Chase Group sold 10,194,732 shares in the aggregate and certain other stockholders of the Company sold 1,650,268 shares in the aggregate, including one of the Company s executive officers who sold 45,000 shares. Chase Oil Corporation granted the underwriters an option to purchase up to 1,776,615 additional shares to cover over-allotments, which was fully exercised on December 19, 2007. The Company did not receive any proceeds from the sale of its common stock in this secondary offering.

Note B. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of Resources include the accounts of Resources and its wholly owned subsidiaries, including CEHC. All material intercompany balances and transactions have been eliminated.

Interim financial statements. The accompanying consolidated financial statements of the Company have not been audited by the Company s independent registered public accounting firm, except that the consolidated balance sheet at December 31, 2007 is derived from audited financial statements. In the opinion of management, the accompanying financial statements reflect all adjustments necessary to present fairly the Company s financial position at June 30, 2008, its income for the three and six months ended June 30, 2008 and 2007 and its cash flows for the six months ended June 30, 2008 and 2007. All such adjustments are of a normal recurring nature. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation. The results for interim periods are not necessarily indicative of annual results.

Certain disclosures have been condensed or omitted from these financial statements. Accordingly, these financial statements should be read with the audited consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2007.

Oil and gas sales and imbalances. Oil and gas revenues are recorded at the time of delivery of such products to pipelines for the account of the purchaser or at the time of physical transfer of such products to the purchaser. The Company follows the sales method of accounting for oil and gas sales, recognizing revenues based on the Company s share of actual proceeds from the oil and gas sold to purchasers. Oil and gas imbalances are generated on properties for which two or more owners have the right to take production in-kind and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well, but the Company does not record any receivable to or payable from the other owners unless the imbalance has reached a level whereby it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance.

At June 30, 2008, the Company had a gas imbalance liability, included in *Asset retirement obligations and other long-term liabilities* in the accompanying consolidated balance sheet of approximately $464,000 related to the Company s overtake position of 83,714 Mcf on certain wells and a gas imbalance receivable, included in *Other assets* in the accompanying consolidated balance sheet of approximately $347,000 related to the Company s undertake position of 77,171 Mcf on certain wells.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held. During the three and six months ended June 30, 2008, the Company did not retire any treasury stock.

General and administrative expense. The Company receives fees for its operation of jointly owned oil and gas properties and records such reimbursements as reductions of General and administrative expense. Such fees totaled approximately $265,000 and $221,000 for the three months ended June 30, 2008 and 2007, respectively, and $504,000 and $630,000 for the six months ended June 30, 2008 and 2007, respectively.

Note C. *Exploratory well costs*

Costs of drilling exploratory wells are capitalized, pending management s determination of whether the wells have found proved reserves. If proved reserves are found, the costs remain capitalized. If proved reserves are not found, the capitalized costs of drilling the well are charged to expense. Management makes this determination as soon as possible after completion of drilling considering the guidance provided in Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies and FASB Staff Position (FSP) No. 19-1, Accounting for Suspended Well Costs.

The following table provides an aging, as of June 30, 2008 and December 31, 2007, of capitalized exploratory well costs based on the date drilling was completed:

(in thousands)	**June 30, 2008**	**December 31, 2007**
Wells in progress	$ 1,038	$ 4,199
Capitalized exploratory well costs that have been capitalized for a period of one year or less	15,240	16,857

Capitalized exploratory well costs that have been capitalized for a period greater than one year		
Total exploratory well costs	$ 16,278	$ 21,056

As of June 30, 2008, the capitalized exploratory well costs of approximately $16.3 million had been deferred for a period of one year or less and were related primarily to the Company s New Mexico shelf properties and emerging resource plays.

As of December 31, 2007, the capitalized exploratory well costs of approximately $21.1 million had been deferred for a period of one year or less and were related primarily to the Company s New Mexico shelf and New Mexico basin properties.

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Note D. ***Fair value measurements***

The Company adopted SFAS No. 157, Fair Value Measurements, (SFAS No. 157) effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. In February 2008, the FASB issued FSP No. 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, investments and interest rate swaps. Our valuation models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. We utilize our counterparties valuations to assess the reasonableness of our prices and valuation techniques.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Level 3 instruments primarily include derivative instruments, such as basis swaps, commodity price collars and floors, as well as investments. Our valuation models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although we utilize our counterparties valuations to assess the reasonableness of our prices and valuation techniques, we do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

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As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table summarizes the valuation of the Company s financial instruments by SFAS No. 157 pricing levels as of June 30, 2008:

	Fair value measurements using			
(in thousands)	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total carrying value at June 30, 2008
Oil and natural gas derivative swap contracts	$	$(143,402)	$	$ (143,402)
Oil and natural gas derivative collar contracts			(15,926)	(15,926)
Total financial liabilities	$	$(143,402)	$(15,926)	$ (159,328)

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy (in thousands):

(in thousands)	Derivatives
Balance as of January 1, 2008	$ 1,866
Total gains or (losses), realized or unrealized	(18,214)
Purchases, issuances, and settlements	422
Balance as of June 30, 2008	$ (15,926)
Total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets and/or liabilities still held at the reporting date	$ (17,792)

Note E. ***New accounting pronouncements***

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115, which became effective in 2008. SFAS No. 159 permits entities to measure eligible financial assets, financial liabilities and firm commitments at fair value, on an instrument-by-instrument basis, that are otherwise not permitted to be accounted for at fair value under other generally accepted accounting principles. The fair value measurement election is irrevocable and subsequent changes in fair value must be recorded in earnings. The Company adopted this statement January 1, 2008, and the Company did not elect the fair value option for any of its eligible financial instruments or other items. As such, the adoption had no impact on the Company s consolidated financial statements.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, Amendment of FASB Interpretation No. 39 (FIN No. 39-1). FIN No. 39-1 clarifies that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement. FIN No. 39-1 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company adopted FIN No. 39-1 effective January 1, 2008, and it has had no material impact on the Company s consolidated financial statements.

In June 2007, the FASB ratified a consensus opinion reached by the Emerging Issues Task Force (EITF) on EITF Issue 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. EITF Issue 06-11 requires an employer to recognize tax benefits realized from dividend or dividend equivalents paid to employees for certain share-based payment awards as an increase to additional paid-in capital and include such amounts in the pool of excess tax benefits available to absorb future tax deficiencies on share-based payment awards. If an entity s estimate of forfeitures increases (or actual forfeitures exceed the entity s estimates), or if an award is no longer expected to vest, entities should reclassify the dividends or dividend equivalents paid on that award from retained earnings to compensation cost. However, the tax benefits from dividends that are reclassified from additional paid-in capital to the income statement are limited to the entity s pool of excess tax benefits available to absorb tax deficiencies on the date of reclassification. The adoption of EITF Issue 06-11 has not had a significant effect on the Company s financial statements since it historically has accounted for the income tax benefits of dividends paid for share-based payment awards in the manner described in the consensus.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141(R)), which replaces FASB Statement No. 141. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be the Company s fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations the Company consummates after the effective date.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an Amendment of ARB No. 51. SFAS No. 160 requires that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS No. 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008, which will be the Company s fiscal year 2009. Based upon the Company s June 30, 2008 consolidated balance sheet, the statement would have no impact.

In December 2007, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin (SAB) No. 110, Share-Based Payment (SAB No. 110). SAB No. 110 amends SAB No. 107, Share-Based Payment, and allows for the continued use, under certain circumstances, of the simplified method in developing an estimate of the expected term on stock options accounted for under SFAS No. 123R, Share-Based Payment (revised 2004). SAB No. 110 is effective for stock options granted after December 31, 2007. The Company continued to use the simplified method in developing an estimate of the expected term on stock options granted in the first and second quarters of 2008. The Company does not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its shares of common stock have been publicly traded.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities (SFAS No. 161), which amends and expands the disclosure requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), to provide an enhanced understanding of an entity s use of derivative instruments, how they are accounted for under SFAS No. 133 and their effect on the entity s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective as of January 1, 2009. The Company is currently evaluating the impact on its consolidated financial statements of adopting SFAS No. 161.

Note F. *Asset retirement obligations*

The Company s asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their production lives, in accordance with applicable state laws. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

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The following table summarizes the Company s asset retirement obligation transactions recorded in accordance with the provisions of SFAS No. 143 during the six months ended June 30, 2008 and 2007:

	Six months ended June 30,	
(in thousands)	2008	2007
Asset retirement obligations, beginning of period	$ 9,418	$ 8,700
Liability incurred upon acquiring and drilling wells	309	131
Accretion expense	301	228
Revisions to estimated cash flows	328	(1,393)
Asset retirement obligations, end of period	$10,356	$ 7,666

Note G. ***Stockholders equity and stock issued subject to limited recourse notes***

Equity commitments. Pursuant to a stock purchase agreement (the Stock Purchase Agreement) entered into on August 13, 2004, the Company obtained private equity commitments totaling $202.5 million, comprised of equity commitments from fourteen private investors (the Private Investors) of approximately $188.9 million and equity commitments from the five original officers (the Officers) of the Company in the aggregate amount of $13.6 million. The original commitments were subject to call by a vote of the board of directors over a four year period beginning August 13, 2004 (the Take-Down Period), with the first date on which capital was called being August 13, 2004. Subsequent calls were made on November 11, 2004, June 22, 2005, December 7, 2005 and February 10, 2006. The percentage of total commitments called per capital call date was approximately 15.0 percent, 23.3 percent, 10.0 percent, 15.0 percent and 22.0 percent, respectively. In conjunction with the exchange of CEHC common stock for Resources common stock as of the date of the Combination, the remaining 14.7 percent of these private equity commitments was terminated.

In addition to this arrangement between the Private Investors and the Officers, certain employees and executive officers of the Company entered into separate subscription agreements with the Company. The officers and employees equity purchases were paid in a combination of cash and the issuance of notes payable to the Company with recourse only to any equity security of the Company held by the respective officer or employee (the Purchase Notes). Based on guidance contained in SFAS No. 123R, the agreements to sell stock to the Officers and certain employees subject to Purchase Notes are accounted for as the issuance of options (Bundled Capital Options for the Officers and Capital Options for certain employees) on the dates that the various subscription agreements were signed and the purchase commitments were made.

Capital calls. From inception of the Company through February 23, 2006, the Private Investors purchased 16,113,170 Preferred Units for $161.1 million in cash. The Officers had purchased 2,240,083 CEHC common shares and 938,303 Preferred Units for $3.6 million in cash and Purchase Notes totaling $8.0 million. Certain employees purchased 425,221 Preferred Units for $1.0 million in cash and Purchase Notes totaling $3.8 million.

6% Series A preferred stock. Preferred stock dividends were generally paid on the anniversary of date of issue. There were no dividend payments made during the three and six months ended June 30, 2008, because there was no outstanding preferred stock. Preferred stock dividends of approximately $98,000 and $132,000 were paid during the three and six months ended June 30, 2007, respectively. As discussed in Note A *Organization and nature of operations* and below, the majority of the CEHC preferred stock was converted into Resources common stock on the Combination date. Final dividend payments on converted CEHC 6% Series A Preferred Stock were made in March 2006.

Dividend payments continued to be made to the eighteen employee shareholders that did not convert their shares of CEHC preferred stock to Resources common stock through April 16, 2007. On April 16, 2007, these CEHC preferred shares were exchanged for 190,972 shares of the Company s common stock. These shares are reported as if converted on the Combination date. Final dividend payments on this final portion of converted CEHC 6% Series A Preferred Stock were made on April 16, 2007.

Purchase Notes. On April 23, 2007, the Company s executive officers repaid their Purchase Notes in full, including principal of $9,426,000 and accrued interest of $1,037,000. The agreements to sell stock to the executive officers of the Company subject to Purchase Notes were accounted for as the issuance of options. As such, the repayment of the executive officer Purchase Notes represents the full exercise of the options on the Bundled Capital Options (as defined below) the Officers held as well as the Capital Options (as defined below) of one certain employee who is currently an executive officer.

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At June 30, 2008, all Purchase Notes from all employees had been paid in full. As such, the repayment of the Purchase Notes represents the full exercise of the options on the Capital Options the certain employees held.

The following table summarizes the Capital Options activity for the six months ended June 30, 2008:

	Number of Capital Options	Weighted average exercise price
Six months ended June 30, 2008		
Outstanding at beginning of period	38,385	$ 8.34
$10 Capital Options exercised	(38,385)	$ 8.34
Outstanding at end of period		$
Vested outstanding at end of period		$

Conversion of CEHC 6% Series A Preferred Stock and CEHC common stock. On February 27, 2006, concurrent with the closing of the Combination described in Note A *Organization and nature of operations*, the majority of the shares of CEHC preferred stock and shares of CEHC common stock outstanding were converted to shares of Resources common stock, as described below.

Eighteen employee shareholders owning an aggregate of 254,621 shares of CEHC preferred stock and 127,313 shares of CEHC common stock did not convert their shares to Resources common stock at the date of the Combination. On April 16, 2007, these remaining shares of CEHC were exchanged for 318,285 shares of the Company s common stock. These shares are reported as if converted on the Combination date. In addition, CEHC made a final dividend payment to these eighteen employee shareholders on their CEHC preferred stock in the aggregate amount of approximately $99,000 on April 16, 2007.

Also in conjunction with the Combination described in Note A *Organization and nature of operations* and the conversion of CEHC preferred stock into Resources common stock at the ratio of 0.75:1, the CEHC Bundled Capital Options were converted into Resources Bundled Capital Options and CEHC Capital Options were converted into Resources Capital Options. The Resources Capital Options are considered to be exercisable for 1.25 shares of Resources common stock.

Treasury stock. On June 12, 2008, the restrictions on five executive officers restricted stock awards lapsed. Immediately upon the lapse of restriction, these executive officers were liable for certain federal income taxes on the value of such shares. In accordance with the Company s 2006 Stock Incentive Plan and the applicable restricted stock award agreements, four of such officers elected to deliver shares to the Company to satisfy such tax liability, and the Company withheld 3,142 shares to be held as treasury stock in the approximate amount of $125,000, the amount of the executive officers federal tax liability.

Note H. *Stock incentive plan*

The Concho Resources Inc. 2006 Stock Incentive Plan (together with applicable option agreements and restricted stock agreements, the Plan) provides for granting stock options and restricted stock awards to employees and individuals associated with the Company.

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All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If a grantee terminates employment or other services prior the lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding, subject to the discretion of the compensation committee. A summary of the Company s restricted stock awards during the six months ended June 30, 2008 is presented below:

	Number of common shares	Grant date fair value
Restricted stock:		
Outstanding at December 31, 2007	371,549	
Shares granted	80,508	$ 35.17
Shares cancelled / forfeited	(35,262)	
Lapse of restrictions	(37,001)	
Outstanding at June 30, 2008	379,794	

The Company recorded stock-based compensation for restricted stock of $468,000 and $560,000, which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations, for the three months ended June 30, 2008 and 2007, respectively. The Company recorded stock-based compensation for restricted stock of $862,000 and $781,000, which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations, for the six months ended June 30, 2008 and 2007, respectively. Future stock-based compensation expense related to restricted stock outstanding at June 30, 2008 for the remaining six months of 2008 and the years ending December 31, 2009, 2010 and 2011 is expected to be approximately $1,358,000, $1,930,000, $1,162,000 and $354,000, respectively.

The income tax benefit recognized in the accompanying statement of operations for restricted stock was approximately $187,000 and $235,000 for the three months ended June 30, 2008 and 2007, respectively, and $341,000 and $327,000 for the six months ended June 30, 2008 and 2007, respectively. The Company had deductions in current taxable income of $771,000 and $340,000 for the three months ended June 30, 2008 and 2007, respectively, and $1.2 million and $425,000 for the six months ended June 30, 2008 and 2007, respectively, related to restricted stock awards.

Stock option awards. In calculating compensation expense for options granted during the six months ended June 30, 2008, the Company estimated the fair value of each grant using the Black-Scholes option-pricing model. Assumptions utilized in the model are shown below.

	2008
Risk-free interest rate	3.18%
Expected term (years)	6.22
Expected volatility	37.28%
Expected dividend yield	0.00%

As permitted by SAB No. 110, the Company used the simplified method to calculate the expected term for stock options granted during the three and six months ended June 30, 2008, since it does not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its shares of common stock have been publicly traded. Expected volatilities are based on a combination of historical and implied volatilities of comparable companies.

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A summary of the Company s stock option activity under the Plan for the six months ended June 30, 2008 is presented below:

	Six months ended June 30, 2008	
	Number of options [(a)]	Weighted Average Exercise Price
Stock options:		
Outstanding at beginning of period	3,011,722	$ 9.71
Options granted	545,555	$22.80
Options forfeited	(250,593)	$14.91
Options exercised	(262,713)	$ 9.03
Outstanding at end of period	3,043,971	$11.69
Exercisable at end of period	717,236	$10.21

(a) One option can be exercised for one share of Resources common stock.

The following table summarizes information about the Company s vested stock options outstanding and exercisable at June 30, 2008:

		Number vested and exercisable	Weighted average remaining contractual life	Weighted average exercise price	Intrinsic value
Vested Options					
Exercise price	$ 8.00	1,543,020	2.77 years	$ 8.00	$ 45,210,000
Exercise price	$ 12.00	164,016	5.61 years	$ 12.00	4,150,000
Exercise price	$ 15.40	181,250	7.96 years	$ 15.40	3,969,000
		1,888,286		$ 9.06	$ 53,329,000

Exercisable Options					
Exercise price	$ 8.00	454,224	3.42 years	$ 8.00	$ 13,309,000
Exercise price	$ 12.00	106,762	7.28 years	$ 12.00	2,701,000
Exercise price	$ 15.40	156,250	7.96 years	$ 15.40	3,422,000
		717,236		$ 10.21	$ 19,432,000

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The following table summarizes information about stock-based compensation for options which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations for the three and six months ended June 30, 2008 and 2007:

	Three months ended June 30,		Six months ended June 30,	
	2008	**2007**	**2008**	**2007**
Grant date fair value:				
Time Vesting options [(a)]	$	$	$ 183,000	$
Current officer stock options [(c)]	794,000		5,090,000	
Total	$ 794,000	$	$5,273,000	$
Stock-based compensation expense from stock options:				
Time Vesting options [(a)]	$ 35,000	$	$ 65,000	$
Performance Vesting options:				
Officers [(b)]	123,000	141,000	264,000	279,000
Certain employee [(b)]	10,000	10,000	20,000	20,000
Current officer stock options [(c)]	1,094,000	418,000	1,818,000	874,000
Total	$1,262,000	$569,000	$2,167,000	$1,173,000

(a) Options vest using a four year graded vesting schedule.

(b) Options granted prior to February 27, 2006, vest using a three year graded vesting schedule.

(c) Vest using a three and four year graded vesting schedule as approved by the Board of Directors.

Future stock-based compensation expense related to stock options outstanding at June 30, 2008 for the remaining six months ended December 31, 2008 and the years ending December 31, 2009, 2010, 2011 and 2012 is expected to be approximately $2,288,000, $2,553,000, $1,151,000, $419,000 and $42,000, respectively.

The income tax benefit recognized in the Company s statements of operations for stock options was $504,000 and $239,000 for the three months ended June 30, 2008 and 2007, respectively, and $858,000 and $492,000 for the six months ended June 30, 2008 and 2007, respectively. The Company had deductions in current taxable income of $3.1 million for the three months ended June 30, 2008, as options on 119,961 shares of common stock were exercised during such quarter. No amounts were treated as deductions to the Company s current taxable income for the three months ended June 30, 2007, since no options were exercised during such quarter. The Company had deductions in current taxable income of $5.3 million for the six months ended June 30, 2008, as options on 262,713 shares of common stock were exercised during such period. No amounts were treated as deductions to the Company s current taxable income for the six months ended June 30, 2007, since no options were exercised during such quarter.

Note I. *Derivative financial instruments*

Cash flow hedges. The Company, from time to time, uses derivative financial instruments as cash flow hedges of its commodity price risks. Commodity hedges are used to (a) reduce the effect of the volatility of price changes on the natural gas and crude oil the Company produces and sells and (b) support the Company s annual capital budgeting and expenditure plans.

Through December 31, 2006, the Company had entered into certain natural gas and crude oil zero cost price collars and crude oil price swaps to hedge a portion of its estimated natural gas and crude oil production for calendar years 2007 and 2008.

On February 8, 2007, the Company entered into one natural gas price swap to hedge an additional portion of its estimated natural gas production for the period of March through December 2007. The contract is for 2,100 MMBtu per day at a fixed index price of $7.40 per MMBtu. The index price is based on the Inside FERC El Paso Permian Basin spot price at the first of each month. On the respective trade dates, the Company has designated all of these derivative instruments as cash flow hedges.

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During the three months ended September 30, 2007, the Company determined that all of its natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133 for the reason stated in the following paragraph. These contracts are referred to as dedesignated hedges.

A key requirement for designation of derivative instruments as cash flow hedges is that at both at inception of the hedge and on an ongoing basis, the hedging relationship is expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. Generally, the hedging relationship can be considered to be highly effective if there is a high degree of historical correlation between the hedging instrument and the forecasted transaction. For all quarters ended prior to July 1, 2007, prices received for the Company s natural gas were highly correlated with the Inside FERC El Paso Natural Gas index (the Index) the Index referenced in all of the Company s natural gas derivative instruments. However, during the quarter ended September 30, 2007, this historical relationship has not met the criteria as being highly correlated. Natural gas produced from the Company s New Mexico shelf assets has a substantial component of natural gas liquids. Prices received for natural gas liquids are not highly correlated to the price of natural gas, but are more closely correlated to the price of oil. During the third quarter of 2007, the price of oil and natural gas liquids, and therefore, the prices the Company received for its natural gas (including natural gas liquids) have risen substantially and at a significantly higher rate than the corresponding change in the Index. This has resulted in a decrease in correlation between the prices received and the Index below the level required for cash flow hedge accounting. According to SFAS No. 133, an entity shall discontinue hedge accounting prospectively for an existing hedge if the hedge is no longer highly effective. Hedge accounting must be discontinued regardless of whether the Company believes the hedge will be prospectively highly effective. The hedge must be discontinued during the period the hedges became ineffective. As a result, any changes in fair value must be recorded in earnings under *(Gain) loss on derivatives not designated as hedges*. Because the gas and liquids prices fluctuate at different rates over time, the loss of effectiveness does not relate to any single date.

Therefore, June 30, 2007, was considered the last date the Company s natural gas hedges were highly effective, and the Company discontinued hedge accounting during the three months ended September 30, 2007 and all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges is recorded each period to *(Gain) loss on derivatives not designated as hedges*. Effective portions of dedesignated hedges, previously recorded in *Accumulated other comprehensive income* (*AOCI*) as of June 30, 2007, remain in *AOCI* and are being reclassified into earnings under *Natural gas revenues*, during the periods which the hedged forecasted transaction affects earnings.

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Derivatives not designated as cash flow hedges. During the six months ended June 30, 2008, the Company entered into crude oil price swaps, a crude oil costless collar and a natural gas price swap to hedge a portion of its estimated production for the remainder of 2008, and for calendar years 2009, 2010, 2011 and 2012. The following table summarizes information about these new derivative instruments as of June 30, 2008:

	Aggregate remaining volume	Daily volume	Index price	Contract period
Derivatives not designated as cash flow hedges:				
Crude oil (volumes in Bbls):				
Price collar	768,000	2,104	$120.00 - $134.60 (a)	1/1/09 - 12/31/09
Price swap	258,000	1,400	$99.25 (a)	7/1/08 - 12/31/08
Price swap	292,000	800	$98.35 (a)	1/1/09 - 12/31/09
Price swap	240,000	658	$128.80 (a)	1/1/10 - 12/31/10
Price swap	336,000	921	$128.66 (a)	1/1/11 - 12/31/11
Price swap	504,000	1,377	$127.80 (a)	1/1/12 - 12/31/12
Natural gas (volumes in MMBtus):				
Price swap	1,825,000	5,000	$8.44 (b)	1/1/09 - 12/31/09

(a) The index prices for the oil price swaps are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index price for the natural gas price collar is based on the Inside FERC-El Paso Permian Basin first-of-the-month spot price.

The Company has not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments are recorded each period to *(Gain) loss on derivatives not designated as hedges.*

Fair value and activity of derivative instruments. The following table sets forth the Company s outstanding crude oil and natural gas zero cost price collars and price swaps at June 30, 2008:

	Fair Market Value Liability (in thousands)	Aggregate remaining volume	Daily volume	Index price	Contract period
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	$ (34,958)	478,400	2,600	$67.50 (a)	7/1/08 - 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	(7,348)	2,484,000	13,500	$6.50 - $9.35 (b)	7/1/08 - 12/31/08
Derivatives not designated as cash flow hedges:					
Crude oil (volumes in Bbls):					
Price collar	(8,578)	768,000	2,104	$120.00 - $134.60 (a)	1/1/09 - 12/31/09
Price swap	(34,558)	625,600	3,400	$85.44 (a) (c)	7/1/08 - 12/31/08
Price swap	(60,264)	1,022,000	2,800	$80.13 (a) (c)	1/1/09 - 12/31/09
Price swap	(2,182)	240,000	658	$128.80 (a)	1/1/10 - 12/31/10
Price swap	(2,522)	336,000	921	$128.66 (a)	1/1/11 - 12/31/11
Price swap	(3,785)	504,000	1,377	$127.80 (a)	1/1/12 - 12/31/12
Natural gas (volumes in MMBtus):					
Price swap	(5,133)	1,825,000	5,000	$8.44 (b)	1/1/09 - 12/31/09
Net liability	$ (159,328)				

(a) The index prices for the oil price swaps are based on the NYMEX-West

Texas Intermediate monthly average futures price.

(b) The index price for the natural gas price collar is based on the Inside FERC-El Paso Permian Basin first-of-the-month spot price.

(c) Amounts disclosed represent weighted average prices.

The following table sets forth the Company s classification of derivative instruments as of June 30, 2008:

(in thousands)		**Fair Market Value Liability**
Derivative liabilities:		
Short-term		(114,504)
Long-term		(44,824)
Net liability	$	(159,328)

The Company s reported oil and gas revenue and average oil and gas prices includes the effects of oil quality and Btu content, gathering and transportation costs, gas processing and shrinkage, and the net effect of the commodity hedges. The following table summarizes the gains and losses reported in earnings related to the commodity financial instruments and the net change in *AOCI:*

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(in thousands)	Three months ended June 30, 2008	2007	Six months ended June 30, 2008	2007
Increase (decrease) in oil and gas revenue from derivative activity:				
Cash (payments) receipts on cash flow hedges in oil sales	$ (13,367)	$ (783)	$ (20,573)	$ 244
Cash receipts from cash flow hedges in gas sales		49		187
Dedesignated cash flow hedges reclassified from AOCI in gas sales	74		(222)	
Total increase (decrease) in oil and gas revenue from derivative activity	$ (13,293)	$ (734)	$ (20,795)	$ 431
Loss on derivatives not designated as cash flow hedges:				
Mark-to-market	$ (90,055)	$	$ (103,247)	$
Cash payments on derivatives not designated as cash flow hedges	(12,401)		(16,387)	
Total loss on derivatives not designated as cash flow hedges	$ (102,456)	$	$ (119,634)	$
Gain (loss) from ineffective portion of cash flow hedges	$ 356	$ 99	$ 920	$ (1,156)
Accumulated other comprehensive income (loss):				
Cash flow hedges:				
Mark-to-market of cash flow hedges gain (loss)	$ (25,903)	$ 992	$ (32,510)	$ (7,457)
Reclassification adjustment for (gains) losses included in net income	13,367	734	20,573	(431)
Net change, before taxes	(12,536)	1,726	(11,937)	(7,888)
Tax effect	4,899	(724)	4,665	3,288
Net change, net of tax	$ (7,637)	$ 1,002	$ (7,272)	$ (4,600)
Dedesignated cash flow hedges:				

Reclassification adjustment for (gains) losses included in net income	$	(74)	$		$	222	$	
Tax effect		29				(87)		
Net change, net of tax	$	(45)	$		$	135	$	

All of the Company s derivatives are expected to settle by December 31, 2012. Based on futures prices as of June 30, 2008, the Company expects a pre-tax loss of $34.5 million to be reclassified into earnings and a pre-tax loss of $0.5 million to be reclassified out of *AOCI* into earnings during the six months ended December 31, 2008 related to the cash flow hedges and the dedesignated cash flow hedges, respectively.

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Note J. ***Long-term debt***

The Company s long-term debt consisted of the following as of the dates indicated:

(in thousands)	June 30, 2008	December 31, 2007
Bank debt:		
1st Lien Credit Facility	$190,000	$216,000
New 2nd Lien Credit Facility	108,900	109,900
Unamortized original issue discount on New 2nd Lien Credit Facility	(447)	(496)
Total long-term debt	$298,453	$325,404
Current portion of New 2nd Lien Credit Facility	2,500	2,000
Total debt	$300,953	$327,404

Refinancing of debt facilities. As of March 27, 2007, the Company amended its revolving credit facility (1st Lien Credit Facility) with a syndicate of banks (1st Lien Banks), repaid its term loan facility, and entered into a new second lien credit facility (the New 2nd Lien Credit Facility), for a term loan facility in the amount of $200 million. The full amount of the facility was funded on the closing date. The New 2nd Lien Credit Facility was issued at a discount of 0.5 percent; thus, the Company received proceeds of $199.0 million. The proceeds from the borrowing were used to repay the existing second lien credit facility in full in the amount of $39.8 million without penalty, reduce the amount outstanding under the 1st Lien Credit Facility by $154.0 million, with the remaining $5.2 million used to pay loan fees, accrued interest and for general corporate purposes. The amount outstanding under the 1st Lien Credit Facility at June 30, 2008 was $190.0 million.

The amendment of the 1st Lien Credit Facility on March 27, 2007, resulted in a $100 million, or 21 percent, reduction of the borrowing base. As such, the pro rata portion of the remaining debt issuance costs associated with the 1st Lien Credit Facility, totaling approximately $766,000, was written off and included in *Interest expense* in the first quarter of 2007. The remaining debt issuance costs of $433,000 associated with the term loan facility repaid in full on March 27, 2007, were written off and included in *Interest expense* in the first quarter of 2007.

The Company paid an arrangement fee of $2.5 million at the date of closing of the New 2nd Lien Credit Facility. This fee is being amortized to *Interest expense* over the five-year term of the facility beginning in April 2007.

The Company entered into the Third Amendment to the 1st Lien Credit Facility on May 19, 2008, which redetermined the borrowing base under the 1st Lien Credit Facility to $550 million at June 30, 2008 and extended the maturity date to February 24, 2011. The Company incurred approximately $1.0 million in deferred loan costs associated with this amendment. These costs will be amortized to *Interest expense* over the new term of the facility.

The New 2nd Lien Credit Facility provides a $200 million term loan, which bears interest, at the Company s option, based on (a) the Bank of America Prime Rate (5.00 percent at June 30, 2008) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and prime rate advances vary, with interest margins of 375 basis points and 225 basis points, respectively, until August 7, 2007, when the Company completed its initial public offering; thereafter, interest margins on Eurodollar rate advances and prime rate advances increased to 425 basis points and 275 basis points, respectively. The Company may select interest periods on Eurodollar rate advances of one, two, three, six, nine and twelve months, subject to availability. Interest is payable at the end of the selected interest period, but no less frequently than quarterly.

The Company is required to repay $0.5 million of the New 2nd Lien Credit Facility on the last day of each calendar quarter. These payments began on June 30, 2007. The maturity date of the New 2nd Lien Credit Facility is March 27, 2012. The Company has the right to prepay the outstanding balance under the New 2nd Lien Credit Facility at any time; however, a two percent prepayment penalty will be incurred on any principal amount prepaid during the second year following the closing and one percent penalty will be incurred during the third year following the closing.

Thereafter, no prepayment penalty will be incurred.

Borrowings under the New 2nd Lien Credit Facility are secured by a second lien on the same assets as are securing the 1st Lien Credit Facility. The second lien is subordinated only to liens securing the 1st Lien Credit Facility. The New 2nd Lien Credit Facility contains various restrictive covenants including (a) maintenance of certain financial ratios including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other non-cash income and expenses of less than 4.5 to 1.0, (ii) maintenance of a ratio of current assets to

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current liabilities, excluding non-cash assets and liabilities related financial derivatives and asset retirement obligations, to be greater than 1.0 to 1.0 and (iii) maintenance of a ratio, as of January 1 and June 30 of each year, of the net present value of the Company s oil and gas properties to total debt to be greater than 1.5 to 1.0; (b) limits on the incurrence of additional indebtedness and certain types of liens; (c) restrictions as to merger and sale or transfer of assets; and (d) a restriction on the payment of cash dividends. The Company was in compliance with all covenants of the New 2nd Lien Credit Facility at June 30, 2008.

The amount outstanding under New 2nd Lien Credit Facility at June 30, 2008 was $111.0 million, net of a discount of $0.4 million, all of which was at the Eurodollar rate.

Repayment of a portion of New 2nd Lien Credit Facility. As described in Note A *Organization and nature of operations*, IPO proceeds in the amount of $86.6 million were used to repay a portion of the New 2nd Lien Credit Facility on August 9, 2007. Subsequent to such repayment the outstanding balance, net of remaining original issue discount, as of August 9, 2007, was $112.4 million. As set forth by this facility s credit agreement, effective on the consummation of the IPO, the interest margins on Eurodollar rate advances and prime rate advances increased to 425 basis points and 275 basis points, respectively, and remain in effect at June 30, 2008.

A pro rata portion of the deferred loan costs associated with the New 2nd Lien Credit Facility were written off to *Interest expense* in August 2007 in the amount of approximately $1.0 million. Additionally, a pro rata portion of the unamortized original issue discount related to the New 2nd Lien Credit Facility was written off to *Interest expense* in August 2007 in the amount of approximately $0.4 million.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding, excluding the unamortized discount of approximately $0.4 million, at June 30, 2008, for the six months ended December 31, 2008 and the years ended December 31, 2009, 2010, 2011 and 2012, are as follows:

(in thousands)	
2008	$ 1,500
2009	2,000
2010	192,000
2011	2,000
2012	103,900
Total	$ 301,400

As of July 31, 2008, the Company amended its 1st Lien Credit Facility, increasing the borrowing base 75% from $550 million to $960 million and extended the maturity date from February 24, 2011 to July 31, 2013. See further discussion in Note O *Subsequent events.*

Note K. *Commitments and contingencies*

Daywork drilling contract commitments. The Company signed a daywork drilling contract with a drilling contractor on July 20, 2006, that provided the Company exclusive use of one rig with an operating day rate of $15,500 for a term that commenced on August 1, 2006 and ended on June 15, 2007. During February 2007, management decided to stack this rig due to budget modifications. The Company incurred contract drilling fees of approximately $1.3 million related to this stacked rig during the year ended December 31, 2007. These costs were minimized as the drilling contractor secured work for the rig and refunded the Company the difference between the current operating day rate pursuant to the contract and the operating day rate received from the new customer.

The Company signed a new daywork drilling contract with the drilling contractor on June 26, 2007, that provided the Company exclusive use of one rig for a term that commenced on July 3, 2007 and ended on January 3, 2008. The Company may direct the rig to locations within the Permian Basin region as needed. The Company is solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that the drilling contractor is liable for its employees, subcontractors and invitees. In addition, the drilling contractor is responsible for pollution or contamination from their equipment. The drilling contractor will release the

Company of any liability for negligence of any party in connection with the drilling contractor. The operating day rate is $14,000. The operating day rate can be revised to reflect changes in costs incurred by the drilling contractor for labor and/or fuel. The contract allows an early termination by the Company with at least a thirty day notice and a payment of the lump sum termination amount equal to the current operating day rate less $6,000, multiplied by the days remaining through the end of the contract term. However, if the drilling contractor secures work for the subject rig with a new customer prior to the end of the contract

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term, the drilling contractor will rebate the Company the difference between the current operating day rate pursuant to the contract and the operating day rate received from the new customer. Beginning on January 4, 2008, this contract was extended through July 31, 2008. The amended contract changed the operating day rate from $14,000 to $13,250. Beginning on March 12, 2008, this contract was amended to change the operating day rate from $13,250 to $12,850 and to extend the term through July 31, 2009. On June 24, 2008, this contract was amended to include an additional rig with an operating day rate of $13,250 for a term ending on July 15, 2009.

The Company signed daywork drilling contracts with Silver Oak Drilling, LLC (Silver Oak), an affiliate of the Chase Group, on August 1, 2006, that provided the Company use of four drilling rigs for a term that commenced on August 1, 2006 and ended on July 31, 2007. The Company could direct the rig to locations located in New Mexico as needed. If the Company moved the rig out of certain New Mexico counties specified in the contract, all effective daywork rates will be increased by an additional $2,000 per day. The Company was solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that Silver Oak was liable for its employees, subcontractors and invitees. In addition, Silver Oak was responsible for pollution or contamination from their equipment. Silver Oak released the Company of any liability for negligence of any party connected to Silver Oak. The operating day rate was $14,500 for two of the contracts and $13,500 for the other two contracts. The operating day rate could be revised to reflect changes in costs incurred by more than 5 percent by Silver Oak for labor, insurance premiums, fuel, and/or an increase in the number of Silver Oak s personnel needed. Under the contracts, the Company must pay the full operating day rate for each day during the contract term. Although there is no early termination provision in the contracts, Silver Oak had a duty to mitigate damages to the Company by reasonably attempting to secure replacement contracts for the rigs if they were released by the Company or if any contract is terminated by Silver Oak prior to the expiration of the term of the contract. The Company would then be entitled to a 75 percent credit for any revenues received by Silver Oak. Even if the Company released the rigs, the Company, with 20 days notice, could withdraw its release and reactivate the contract for the remainder of the term to the extent the rig had not been committed to a third party in mitigation of the Company s damages. During February 2007, management decided to stack these four rigs due to budget modifications. The Company incurred contract drilling fees of approximately $2,973,000 related to these stacked rigs during the year ended December 31, 2007, based on the drilling contracts described above. As of April 1, 2007, the Company began to utilize all four rigs, in order to proceed with its 2007 drilling budget.

The Company signed new daywork drilling contracts with Silver Oak on June 19, 2007, that provides the Company use of four drilling rigs for a term that commenced on August 1, 2007 and are in effect until drilling operations are completed on specified wells or for a term of one year. If any well commenced during the term of the contract is drilling at the expiration of the one year primary term, drilling will continue under the terms of the contract until drilling operations for that well have been completed. The Company may direct the rig to locations located in New Mexico as needed. The Company is solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that Silver Oak is liable for its employees, subcontractors and invitees. In addition, Silver Oak is responsible for pollution or contamination from their equipment. Silver Oak will release the Company of any liability for negligence of any party connected to Silver Oak. The operating day rate is $14,500 for two of the contracts and $13,500 for the other two contracts. The operating day rate can be revised to reflect changes in costs incurred by more than 5 percent by Silver Oak for labor, insurance premiums, fuel, and/or an increase in the number of Silver Oak s personnel needed. Under the contract, the Company must pay the full operating day rate for each day during the contract term. Although there is no early termination provision in the contract, Silver Oak has a duty to mitigate damages to the Company by reasonably attempting to secure replacement contracts for the rigs if they are released by the Company or if any contract is terminated by Silver Oak prior to the expiration of the term of the contract. The Company will then be entitled to a 75 percent credit for any revenues received by Silver Oak. Even if the Company releases the rigs, the Company, with 20 days notice, may withdraw its release and reactivate the contracts for the remainder of the term to the extent the subject rig has not been committed to a third party in mitigation of damages. Beginning on June 30, 2008, these contracts were amended to change the operating day rates from $14,500 to $15,000 and from $13,500 to $14,000 and to extend the term through August 1, 2009.

Note L. *Income taxes*

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109 Accounting for Income Taxes. The Company and its subsidiaries file federal corporate income tax returns on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by United States federal and state taxing authorities. In determining the interim period income tax provision, the Company utilizes an estimated annual effective tax rate.

The Company adopted the provisions of FASB Interpretation No. 48 Accounting for Uncertainty in Income Taxes (FIN No. 48) an interpretation of FASB Statement No. 109 Accounting for Income Taxes, on January 1, 2007. At the time of adoption and as of June 30, 2008, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2004 through 2007 remain subject to examination by major tax jurisdictions.

The FASB issued FIN No. 48-1, Definition of Settlement in FASB Interpretation No. 48, (FIN No. 48-1) to clarify when a tax position is effectively settled. FIN No. 48-1 provides guidance in determining the proper timing for recognizing tax benefits and applying the new information relevant to the technical merits of a tax position obtained during a tax authority examination. FIN No.

48-1 provides criteria to determine whether a tax position is effectively settled after completion of a tax authority examination, even if the potential legal obligation remains under the statute of limitations. The Company s adoption of this pronouncement did not have a significant effect on its consolidated financial statements.

The Company s provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses.

Note M. ***Related parties***

Contract Operator Agreement and Transition Services Agreement. On February 27, 2006, the Company signed a Contract Operator Agreement with Mack Energy Corporation (MEC), an affiliate of the Chase Group, whereby the Company engaged MEC as contract operator to provide certain services with respect to the Chase Group Properties. The initial term of the Contract Operator Agreement was 5 years commencing on March 1, 2006 and ending on February 28, 2011. The Company and MEC entered into a Transition Services Agreement on April 23, 2007, which terminated the Contract Operator Agreement and under which MEC continued to provide certain field level operating services on the Chase Group Properties. Under the Transition Services Agreement, MEC provided field level services, including pumping, well service oversight and supervision and certain equipment for workover and recompletion services, at costs prevailing in the area of the subject properties, but not to exceed charges for comparable services by and among MEC and its affiliates. MEC performed substantially similar services on behalf of the Company under the prior Contract Operator Agreement prior to its termination. In accordance with its terms, the Transition Services Agreement was terminated automatically by its terms on August 7, 2007 upon the Company s completion of the IPO. Upon termination, the Company s employees along with third party contractors assumed the operation of the subject properties.

The Company incurred charges from MEC of approximately $260,000 and $1.5 million for the three and six months ended June 30, 2008, respectively.

The Company incurred charges from MEC of approximately $5.1 million and $10.2 million for the three and six months ended June 30, 2007, respectively, for services rendered under the Contract Operator Agreement and Transition Services Agreement.

At June 30, 2008, the Company had outstanding invoices payable to MEC of approximately $5,000 which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

At December 31, 2007, the Company had outstanding invoices payable to MEC of approximately $0.4 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

Other related party transactions. The Company also has engaged in transactions with certain other affiliates of the Chase Group, including Silver Oak, an oilfield services company, a supply company, a drilling fluids supply company, a pipe and tubing supplier, a fixed base operator of aircraft services and a software company.

The Company incurred charges from these related party vendors of approximately $5.7 million and $13.1 million for the three and six months ended June 30, 2008, respectively, for services rendered and charges of approximately $10.7 million and $22.1 million for the three and six months ended June 30, 2007, respectively, for services rendered.

The Company had outstanding invoices payable to the other related party vendors identified above of approximately $264,000 and $1.7 million at June 30, 2008 and December 31, 2007, respectively, which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheets.

Overriding royalty and royalty interests. Certain members of the Chase Group own overriding royalty interests in certain of the Chase Group Properties. The amount paid attributable to such interests was approximately $816,000 and $1.6 million for the three and six months ended June 30, 2008, respectively. The amount paid attributable to such interests was approximately $458,000 and $1.0 million for the three and six months ended June 30, 2007, respectively. The Company owed these owners royalty payments of approximately $322,000 and $315,000 as of June 30, 2008 and December 31, 2007, respectively.

Royalties are paid on certain properties located in Andrews County, Texas to a partnership of which one of the Company s directors is the general partner, and who also owns a 3.5% partnership interest. The Company paid this partnership approximately $81,000 and $164,000 for the three and six months ended June 30, 2008, respectively. The Company paid approximately $36,000 and $59,000 for the three and six months ended June 30, 2007, respectively. The Company owed this partnership royalty payments of approximately $30,000 and $29,000 as of June 30, 2008 and

December 31, 2007, respectively.

In April 2005, the Company acquired certain working interests in 46,861 gross (26,908 net) acres located in Culberson County, Texas from an entity partially owned by a person who became an executive officer of the Company immediately following such acquisition. In connection with this acquisition, such entity retained a 2% overriding royalty interest in the acquired properties, which overriding royalty interest later became owned equally by such officer and a non-officer employee of the Company. During the three and six months ended June 30, 2008, no payments were made related to this overriding royalty interest. The amount attributable to such interest was approximately $2,000 during the three and six months ended June 30, 2007. Effective March 31, 2008, the referenced executive officer resigned from the Company.

Prospect participation. Subsequent to the closing of the Combination, the Company acquired working interests from Caza in certain lands in New Mexico in which Caza owns an interest.

There were no amounts paid to Caza for these interests during the three and six months ended June 30, 2008, and during the three months ended June 30, 2007. The Company paid Caza approximately $3,000 for the six months ended June 30, 2007 for delay rentals.

At June 30, 2008 and December 31, 2007, the Company had no outstanding invoices owed to Caza.

Note N. *Net income per share*

Basic net income per share is computed by dividing net income applicable to common shareholders by the weighted average number of common shares treated as outstanding for the period. As discussed in Note G *Stockholders equity and stock issued subject to limited recourse notes* , agreements to sell stock to the Officers and certain employees subject to Purchase Notes are accounted for as options (Bundled Capital Options and Capital Options , respectively). As a result, Bundled Capital Options and Capital Options are excluded from the weighted average number of common shares treated as outstanding during each period until the Purchase Notes are paid in full, thus exercising the options. All Bundled Capital Options were exercised prior to June 30, 2007. All Capital Options were exercised prior to March 31, 2008.

The computation of diluted income per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company. These amounts include unexercised Bundled Capital Options, Capital Options, stock options and restricted stock (as issued under the Plan, as described in Note H *Stock incentive plan*. Potentially dilutive effects are calculated using the treasury stock method.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the three and six months ended June 30, 2008 and 2007:

	Three months ended June 30,		**Six months ended June 30,**	
(in thousands)	**2008**	**2007**	**2008**	**2007**
Weighted average common shares outstanding:				
Basic	75,665	57,747	75,569	56,369
Dilutive Bundled Capital Options		660		1,695
Dilutive Capital Options		160	12	204
Dilutive common stock options		996	1,206	921
Dilutive restrictive stock		62	247	71
Diluted	75,665	59,625	77,034	59,260

For the three months ended June 30, 2008, the computation of diluted net loss per share was antidilutive; therefore, the amounts reported for basic and diluted net loss per share were the same. Restricted stock and options equivalent to 379,794 and 3,043,971 shares of common stock were not included in the computation of diluted income (loss) per share for the three months ended June 30, 2008, respectively, as inclusion of these items would be antidilutive.

For the three and six months ended June 30, 2007, and for the six months ended June 30, 2008, the effects of all potentially dilutive securities including Bundled Capital Options, Capital Options and stock options were included in the computation of diluted earnings per share because the Company had net income applicable to common shareholders and, therefore, there were no antidilutive effects.

Note O. ***Subsequent events***

New derivative instruments. On July 25, 2008, the Company entered into two crude oil price swaps to hedge a portion of its estimated crude oil production for calendar years 2008 and 2009. The contracts are for 49,000 Bbls per month for the remainder of 2008 (August through December) at a fixed price of $124.35 per Bbl, and 29,000 Bbls per month for calendar year 2009 at a fixed price of $125.10 per Bbl. The Company has not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

Henry Acquisition. On July 31, 2008, the Company closed the acquisition of Henry Petroleum LP and certain affiliated entities (collectively Henry) (the Acquisition). Cash paid at closing totaled approximately $560 million. The Company financed the Acquisition with proceeds raised from a $250.0 million private placement of 8.3 million shares of the Company s common stock, together with funds available under a new amended and restated senior credit facility (the Senior Credit Facility), as further described below. After the closing of the Henry transaction and the additional interests acquired concurrently as described below, the Company has approximately $285 million of availability under the Senior Credit Facility.

In connection with the Acquisition, the Company also purchased certain additional non-operated rights and interests in Henry s oil and gas properties from certain persons affiliated with Henry (such transactions, collectively, the Along-side Transactions) for aggregate cash consideration of approximately $28.0 million.

The following table shows the sources and uses of funds for the above referenced transactions on July 31, 2008:

(in thousands)	
Sources of Funds:	
Proceeds from Issuance of Common Shares	$ 250,000
Initial Borrowing under Senior Credit Facility	675,000
Total Sources of Funds	$ 925,000
Uses of Funds:	
Purchase of Henry Equity Interests	$ 536,830
Repay 1st Lien Credit Facility	194,389
Repay 2nd Lien Credit Facility	113,189
Purchase of Along-side Property Interests	28,039
Fees and Expenses	24,829
Working Capital and General Corporate Purposes	27,724
Total uses of Funds	$ 925,000

Common Stock Purchase Agreement. On June 5, 2008, the Company also entered into a Common Stock Purchase Agreement (the Purchase Agreement) with certain unaffiliated third-party investors (the Purchasers) to sell approximately 8.3 million shares of the Company s common stock in a private placement (the Private Placement) for aggregate cash consideration of approximately $250.0 million, for a negotiated price of $30.11 per share. The Private Placement closed simultaneously with the Acquisition on July 31, 2008.

The closing of the Private Placement was subject to customary closing conditions, as well as certain other conditions, including (i) the closing of the Acquisition and (ii) the execution by the Company and the Purchasers of a registration rights agreement that will require the Company to file a shelf registration statement for the benefit of the Purchasers within 60 days after the closing of the Private Placement.

The Private Placement is being made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof.

Amended and Restated Credit Facility. As of July 31, 2008, the Company amended and restated its senior credit facility in various respects including, increasing the borrowing base to $960 million, subject to semiannual redetermination, and extending the maturity date from February 24, 2011 to July 31, 2013 (the Senior Credit Facility, as defined above). The initial borrowing under the Senior Credit Facility was

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$675 million. The Company paid an arrangement fee of $14.4 million at the date of closing of the Senior Credit Facility. This fee is being amortized to *Interest expense* over the remaining five year term of the facility beginning in August 2008.

Advances on the Senior Credit Facility bear interest, at the Company s option, based on (a) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (5.00 percent at July 31, 2008) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 125 - 275 basis points and 0 - 125 basis points, respectively, per annum depending on the balance outstanding. The Company pays commitment fees on the unused portion of the available borrowing base ranging from 25 - 50 basis points per annum.

The Senior Credit Facility also includes a same-day advance facility under which the Company may borrow funds on a daily basis from the 1st Lien Banks administrative agent. Advances made on this same-day basis cannot exceed $25 million and the maturity dates cannot exceed fourteen days. The interest rate on this facility is the JPM Prime Rate plus the applicable interest margin.

The Company s obligations under the Senior Credit Facility are secured by a first lien on substantially all of the Company s oil and gas properties. In addition, all of the Company s subsidiaries are guarantors, and all subsidiary general partner, limited partner and membership interests owned by the Company have been pledged to secure borrowings under the Senior Credit Facility. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses no greater than 4.0 to 1.0, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations, to be no less than 1.0 to 1.0; (b) limits on the incurrence of additional indebtedness and certain types of liens; (c) restrictions as to merger and sale or transfer of assets; and (d) a restriction on the payment of cash dividends.

Note P. ***Supplementary information***

Capitalized costs

(in thousands)	**June 30, 2008**	**December 31, 2007**
Oil and gas properties:		
Proved	$1,432,392	$1,303,665
Unproved	242,771	251,353
Less accumulated depletion	(209,688)	(167,109)
Net capitalized costs for oil and gas properties	$1,465,475	$1,387,909

Costs incurred for oil and gas producing activities

	Three months ended June 30,		**Six months ended June 30,**	
(in thousands)	**2008**	**2007**	**2008**	**2007**
Property acquisition costs:				
Proved	$ (104)	$ 113	$ 1	$ 113
Unproved	587	3,001	1,349	3,791
Exploration	20,942	30,027	50,507	41,734
Development	45,146	2,072	70,799	17,373

Capitalized asset retirement obligations	1,412	(922)	637	(1,289)
Total costs incurred for oil and gas properties	$67,983	$34,291	$123,293	$61,722

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Item 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included in our Annual Report on Form 10-K for the year ended December 31, 2007.

Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenue and expenses to differ materially from our expectations.

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of producing oil and natural gas properties. Our conventional operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We have also acquired significant acreage positions in unconventional emerging resource plays located in the Permian Basin of Southeast New Mexico, the Central Basin Platform and the Western Delaware Basin of West Texas, the Williston Basin in North Dakota and the Arkoma Basin in Arkansas, where we intend to apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies. Crude oil comprised 59% of our 546.0 Bcfe of estimated net proved reserves as of December 31, 2007, and 60% of our 30.1 Bcfe of production for the year ended December 31, 2007. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 90% of our PV-10 and 50% of our 2,067 wells as of December 31, 2007. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Recent Events

Short-term interruptions in production. During the first quarter of 2008, we experienced short-term interruptions in our production on the New Mexico shelf properties due to operational problems with a natural gas processing plant. There were a total of 10 days of curtailment during the first quarter, and approximately 100 MMcfe of our production was curtailed during this period.

Additionally, on April 7, 2008, a natural gas processing plant through which we process and sell a portion of the production from our New Mexico shelf properties was curtailed for its annual routine maintenance. The plant resumed full operation on April 19, 2008, and we thereafter began restoring production from all of our properties that had been affected. Approximately 450 MMcfe of our production was shut-in as a result of this plant shut-down.

On May 16, 2008, a refinery located in New Mexico shut down for ten days due to repairs. As a result, the Company shut-in approximately 221 MMCFE of production during the ten day period.

Amended credit agreement. We entered into the Third Amendment to the 1st Lien Credit Facility on May 19, 2008, which redetermined the borrowing base under the 1st Lien Credit Facility to $550 million at June 30, 2008.We incurred approximately $1.0 million in deferred loan costs associated with this amendment. These costs will be amortized to *Interest expense* over the new term of the facility. As of July 31, 2008, we amended and restated our 1st Lien Credit Facility, increasing the borrowing base to $960 million and extending the maturity date from February 24, 2011 to July 31, 2013. See further discussion below in Subsequent events.

Treasury stock. On June 12, 2008, the restrictions on five executive officers restricted stock awards lapsed. Immediately upon the lapse of restriction, these executive officers were liable for certain federal income taxes on the value of such shares. In accordance with our 2006 Stock Incentive Plan and the applicable restricted stock award agreements, four of such officers elected to deliver shares to the Company to satisfy such tax liability, and the Company withheld 3,142 shares to be held as treasury stock in the approximate amount of $125,000, the amount of the executive officers federal tax liability.

New derivative instruments. On June 5, 2008, the Company entered into a crude oil costless collar to hedge a portion of its estimated crude oil production for calendar year 2009. The contract is for 64,000 Bbls per month (or 2,104 Bbls per day) for calendar year 2009 with a ceiling of $134.60 per Bbl and a floor of $120.00 per Bbl. The Company has not designated this derivative instrument as a cash flow hedge. Mark-to-market adjustments related to this derivative instrument will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

On June 6, 2008, the Company entered into three crude oil price swaps to hedge a portion of its estimated crude oil production for the calendar years 2010, 2011 and 2012.

Additionally, on July 25, 2008, the Company entered into two crude oil price swaps to hedge a portion of its estimated crude oil production for the calendar years 2008 and 2009. The contracts are for 49,000 Bbls per month for the remainder of 2008 (August through December) at a fixed price of $124.35 per Bbl, and 29,000 Bbls per month for calendar year 2009 at a fixed price of $125.10 per Bbl. The Company has not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

Subsequent events

Henry Acquisition. On July 31, 2008, we closed the acquisition of Henry Petroleum LP and certain affiliated entities (collectively Henry) (the Acquisition). Cash paid at closing totaled approximately $560 million. We financed the Acquisition with proceeds raised from a $250.0 million private placement of 8.3 million shares of our common stock, together with funds available under a new amended and restated senior credit facility (the Senior Credit Facility), as further described below. After the closing of the Henry transaction and the additional interests acquired concurrently as described below, we have approximately $285 million of availability under the Senior Credit Facility.

In connection with the Acquisition, we also purchased certain additional non-operated rights and interests in Henry s oil and gas properties from certain persons affiliated with Henry (such transactions, collectively, the Along-side Transactions) for aggregate cash consideration of approximately $28.0 million.

The following table shows the sources and uses of funds for the above referenced transactions on July 31, 2008:

(in thousands)	
Sources of Funds:	
Proceeds from Issuance of Common Shares	$ 250,000
Initial Borrowing under Senior Credit Facility	675,000
Total Sources of Funds	$ 925,000
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Purchase of Henry Equity Interests	$ 536,830
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Repay 2nd Lien Credit Facility	113,189
Purchase of Along-side Property Interests	28,039
Fees and Expenses	24,829
Working Capital and General Corporate Purposes	27,724
Total uses of Funds	$ 925,000

Common Stock Purchase Agreement. On June 5, 2008, we also entered into a Common Stock Purchase Agreement (the Purchase Agreement) with certain unaffiliated third-party investors (the Purchasers) to sell approximately 8.3 million shares of our common stock in a private placement (the Private Placement) for aggregate cash consideration of approximately $250.0 million, for a negotiated price of $30.11 per share. The Private Placement closed simultaneously with the Acquisition on July 31, 2008.

The closing of the Private Placement was subject to customary closing conditions, as well as certain other conditions, including (i) the closing of the Acquisition and (ii) the execution by us and the Purchasers of a registration rights agreement that will require us to file a shelf registration statement for the benefit of the Purchasers within 60 days after the closing of the Private Placement.

The Private Placement is being made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, pursuant to Section 4(2) thereof.

Amended and Restated Credit Facility. As of July 31, 2008, we amended and restated our Senior Credit Facility in various respects including, increasing the borrowing base to $960 million, subject to semiannual redetermination, and extending the maturity date from February 24, 2011 to July 31, 2013. The initial borrowing under the Senior Credit Facility was $675 million. We paid an arrangement fee of $14.4 million at the date of closing of the Senior Credit Facility. This fee is being amortized to *Interest expense* over the remaining five year term of the facility beginning in August 2008.

Advances on the Senior Credit Facility bear interest, at our option, based on (a) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (5.00 percent at July 31, 2008) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 125 - 275 basis points and 0 - 125 basis points, respectively, per annum depending on the balance outstanding. We pay commitment fees on the unused portion of the available borrowing base ranging from 25 - 50 basis points per annum.

The Senior Credit Facility also includes a same-day advance facility under which we may borrow funds on a daily basis from the 1st Lien Banks administrative agent. Advances made on this same-day basis cannot exceed $25 million and the maturity dates cannot exceed fourteen days. The interest rate on this facility is the JPM Prime Rate plus the applicable interest margin.

Our obligations under the Senior Credit Facility are secured by a first lien on substantially all of our oil and gas properties. In addition, all of our subsidiaries are guarantors, and all subsidiary general partner, limited partner and membership interests owned by us have been pledged to secure borrowings under the Senior Credit Facility. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses no greater than 4.0 to 1.0, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations, to be no less than 1.0 to 1.0; (b) limits on the incurrence of additional indebtedness and certain types of liens; (c) restrictions as to merger and sale or transfer of assets; and (d) a restriction on the payment of cash dividends.

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Results of operations of Concho Resources Inc.

The following table presents selected financial and operating information of Concho Resources Inc. for the three and six months ended June 30, 2008 and 2007:

(in thousands, except price data)	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
	(unaudited)		(unaudited)	
Oil sales	$ 95,408	$43,096	$171,226	$ 82,467
Natural gas sales	41,975	23,007	72,868	43,982
Total operating revenues	137,383	66,103	244,094	126,449
Operating costs and expenses	54,942	46,324	103,147	88,262
Loss on derivatives not designated as hedges	102,456		119,634	
Interest, net and other revenue	3,574	9,866	8,169	20,276
Income (loss) before income taxes	(23,589)	9,913	13,144	17,911
Income tax benefit (expense)	9,169	(3,988)	(5,199)	(7,363)
Net income (loss)	$ (14,420)	$ 5,925	$ 7,945	$ 10,548
Production volumes:				
Oil (MBbl)	899	730	1,786	1,438
Natural gas (MMcf)	3,346	2,953	6,451	5,905
Natural gas equivalent (MMcfe)	8,740	7,330	17,167	14,536
Average prices:				
Oil, without hedges ($/Bbl)	$ 121.00	$ 60.15	$ 107.39	$ 57.16
Oil, with hedges ($/Bbl)	$ 106.13	$ 59.07	$ 95.87	$ 57.33
Natural gas, without hedges ($/Mcf)	$ 12.52	$ 7.77	$ 11.33	$ 7.42
Natural gas, with hedges ($/Mcf)	$ 12.54	$ 7.79	$ 11.30	$ 7.45
Natural gas equivalent, without hedges ($/Mcfe)	$ 17.24	$ 9.12	$ 15.43	$ 8.67
Natural gas equivalent, with hedges ($/Mcfe)	$ 15.72	$ 9.02	$ 14.22	$ 8.70

Bbl *Barrel*

MBbl *Thousand Barrels*

Mcf *Thousand cubic feet*

MMcf *Million cubic feet*

Mcfe *Thousand cubic feet of natural*

	gas equivalent (computed on an energy equivalent basis of one Bbl equals six Mcf)
MMcfe	*Million cubic feet of natural gas equivalent (computed on an energy equivalent basis of one Bbl equals six Mcf)*

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Three months ended June 30, 2008, compared to three months ended June 30, 2007

Oil and gas revenues. Revenue from oil and gas operations was $137.4 million for the three months ended June 30, 2008, an increase of $71.3 million (108%) from $66.1 million for the three months ended June 30, 2007. This increase was primarily because of increased production due to successful drilling efforts during 2008 coupled with substantial increases in realized oil and gas prices. In addition:

average realized oil prices (after giving effect to hedging activities) were $106.13 per Bbl during the three months ended June 30, 2008, an increase of 80% from $59.07 per Bbl during the three months ended June 30, 2007;

total oil production was 899 MBbl for the three months ended June 30, 2008, an increase of 169 MBbl (23%) from 730 MBbl for the three months ended June 30, 2007;

average realized natural gas prices (after giving effect to hedging activities) were $12.54 per Mcf during the three months ended June 30, 2008, an increase of 61% from $7.79 per Mcf during the three months ended June 30, 2007;

total natural gas production was 3,346 MMcf for the three months ended June 30, 2008, an increase of 393 MMcf (13%) from 2,953 MMcf for the three months ended June 30, 2007;

average realized natural gas equivalent prices (after giving effect to hedging activities) were $15.72 per Mcfe during the three months ended June 30, 2008, an increase of 74% from $9.02 per Mcfe during the three months ended June 30, 2007; and

total production was 8,740 MMcfe for the three months ended June 30, 2008, an increase of 1,410 MMcfe (19%) from 7,330 MMcfe for the three months ended June 30, 2007.

See discussion in Recent events about 2007 and 2008 production interruptions due to plant and refinery shut-downs.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. The following is a summary of the effects of commodity hedges for the three months ended June 30, 2008 and 2007:

	Crude Oil Hedges Three months ended June 30,		Natural Gas Hedges Three months ended June 30,	
	2008	**2007**	**2008**	**2007**
	(unaudited)		**(unaudited)**	
Hedging revenue increase (decrease)	$(13,367,000)	$(783,000)	$ 74,000	$ 49,000
Hedged volumes (Bbls and MMBtus, respectively)	236,000	268,000	1,228,000	1,647,000
Hedged revenue increase (decrease) per hedged volume	$ (56.64)	$ (2.92)	$ 0.06	$ 0.03

During the three months ended June 30, 2008, our commodity price hedges decreased oil revenues by $13.4 million ($14.87 per Bbl). During the three months ended June 30, 2007, our commodity price hedges decreased oil revenues by $0.8 million ($1.07 per Bbl). The effect of the commodity price hedges in decreasing oil revenues during the three months ended June 30, 2008 compared to their effect of decreasing oil revenues during the three months ended June 30, 2007 was the result of (1) a higher average market price of NYMEX crude oil of $124.28 per Bbl in 2008 as compared to $65.08 per Bbl in 2007 and (2) the greater price difference between NYMEX and the weighted average hedge price in 2008 as compared to 2007, partially offset by a lower amount of hedged volumes of 236,000 Bbls in 2008 as compared to 268,000 Bbls in 2007.

During the three months ended June 30, 2008, our commodity price hedges increased gas revenues by $0.07 million ($0.02 per Mcf) as a result of the amount reclassified from *AOCI* into natural gas revenues from cash flow hedges that were dedesignated as of June 30, 2007. Cash settlements for these dedesignated natural gas contracts are being recorded to *(Gain) loss on derivatives not designated as hedges*. During the three months ended June 30, 2007, our commodity price hedges increased gas revenues by $0.05 million ($0.02 per Mcf) as a result of the price difference between the market reference price of natural gas and the commodity contract price.

in 2008 as compared to settlements in 2007, partially offset by a lower amount of hedged volumes of 1,228,000 MMBtus in 2008 as compared to 1,647,000 MMBtus in 2007.

Production expenses. Production expenses (including production taxes) were $22.0 million ($2.51 per Mcfe) for the three months ended June 30, 2008, an increase of $9.8 million (80%) from $12.2 million ($1.66 per Mcfe) for the three months ended June 30, 2007. The increase in production expenses is due to: (1) production expenses associated with new wells that were successfully completed in 2008 as a result of our drilling activities and (2) an increase in production taxes as discussed below. Lease operating expenses and workover costs comprised approximately 45% and 57% of production expenses for the three months ended June 30, 2008 and 2007, respectively. These costs per unit of production were $1.14 per Mcfe during the three months ended June 30, 2008, an increase of 20% from $0.95 per Mcfe during the three months ended June 30, 2007. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 5% of lease operating expenses for the three months ended June 30, 2008 and 2007.

The secondary component of production expenses is production taxes, which is directly related to commodity price changes. These costs comprised approximately 55% and 43% of production expenses during the three months ended June 30, 2008 and 2007, respectively. Production taxes per unit of production were $1.38 per Mcfe during the three months ended June 30, 2008, an increase of 92% from $0.72 per Mcfe during the three months ended June 30, 2007. This increase was primarily due to an increase in average natural gas equivalent prices we received.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the three months ended June 30, 2008 and 2007:

	Three months ended June 30,	
	2008	**2007**
(in thousands)	**(unaudited)**	
Geological and geophysical	$424	$ 225
Exploratory dry holes	(19)	5,635
Leasehold abandonments and other	318	4
Total exploration and abandonments	$723	$5,864

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, during the three months ended June 30, 2008 was $0.4 million, an increase of $0.2 million from $0.2 million for the three months ended June 30, 2007. This increase is primarily attributable to a comprehensive seismic survey on our New Mexico shelf properties which was initiated in December 2007.

Our exploratory dry holes expense during the three months ended June 30, 2007 was primarily attributable to three operated exploratory wells that were unsuccessful. The costs associated with one of these wells drilled in the Western Delaware Basin in Culberson County, Texas approximated $2.8 million. Another of these wells, which was drilled in the Southeastern New Mexico Basin in Lea County, New Mexico, had costs of approximately $2.0 million. An additional $0.8 million was charged to exploratory dry hole costs relative to a target zone in the third of these wells in the Southeastern New Mexico Basin in Eddy County, New Mexico which was determined to be dry. This well was completed in a shallower zone which was found to be productive.

For the three months ended June 30, 2008, we recorded $0.3 million of leasehold abandonments, which are primarily related to prospects in Chaves County, New Mexico and Crane County, Texas. We had minimal leasehold abandonments during the three months ended June 30, 2007.

Depreciation and depletion expense. Depreciation and depletion expense was $22.0 million ($2.52 per Mcfe), including $21.6 million associated with oil and gas properties ($2.47 per Mcfe), for the three months ended June 30, 2008, an increase of $4.4 million from $17.6 million ($2.40 per Mcfe), including $17.4 million associated with oil and gas properties ($2.37 per Mcfe), for the three months ended June 30, 2007. The increase in depreciation and depletion expense was primarily due to capitalized costs associated with new wells that were successfully completed in 2007 and 2008 as a result of our drilling activities. Despite an increase in total proved reserves, the depreciation and depletion rate per Mcfe increased from the three months ended June 30, 2007 to the three months ended June 30, 2008, due to an increase in capitalized costs as a result of our successful development and exploratory drilling program. The crude oil price utilized for our estimate of proved oil and gas reserves was $136.50 as of June 30, 2008, an increase of

$69.25 (103%) from $67.25 as of June 30, 2007. The natural gas price utilized for our estimate of proved oil and gas reserves was $13.10 as of June 30, 2008, an increase of $6.30 (93%) from $6.80 as of June 30, 2007.

Impairment of oil and gas properties. In accordance with SFAS No. 144, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets during the three months ended June 30, 2008, we recognized a non-cash charge against earnings of $0.1 million, which was comprised primarily of a well located in Lea County, New Mexico. For the three months ended June 30, 2007, we recognized a non-cash charge against earnings of $2.1 million, primarily related to a well drilled on acreage in Schleicher County, Texas.

Contract drilling fees stacked rigs. As discussed in our Annual Report on Form 10-K for the year ended December 31, 2007, we determined in January 2007 to reduce our drilling activities for the first three months of 2007. As a result, we recorded an expense during the three months ended June 30, 2007 of approximately $0.9 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007. These costs were minimized during the first six months of 2007 as one contractor secured work for a rig for 71 days during that period and charged us only the difference between the then-current operating day rate pursuant to the contract and the lower operating day rate received from the new customer.

General and administrative expenses. General and administrative expenses were $8.6 million ($0.98 per Mcfe) for the three months ended June 30, 2008, an increase of $1.0 million (13%) from $7.6 million ($1.04 per Mcfe) for the three months ended June 30, 2007. Included in general and administrative expense was non-cash stock-based compensation of $1.7 million during the three months ended June 30, 2008 and $1.1 million during the three months ended June 30, 2007. General and administrative expenses, excluding non-cash stock-based compensation, (Net general expense) were $6.9 million ($0.78 per Mcfe) for the three months ended June 30, 2008, an increase of $0.4 million (6%) from $6.5 million ($0.89 per Mcfe) for the three months ended June 30, 2007. The increase in Net general expenses during the three months ended June 30, 2008 was primarily due to an increase in the number of employees and related personnel expenses.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $0.3 million and $0.2 million during the three months ended June 30, 2008 and 2007, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Bad debt expense. On May 20, 2008, we entered into a temporary purchase agreement with an oil purchaser to buy a portion of the oil affected as a result of the New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared Chapter 11 bankruptcy in a Delaware federal bankruptcy court. We fully reserved the receivable amount due from this purchaser of approximately $1.8 million as of June 30, 2008.

Loss on derivatives not designated as cash flow hedges. As explained in *Hedging activities*, during the three months ended September 30, 2007, we determined that all of our natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133. If the hedge is no longer highly effective, according to SFAS No. 133, an entity shall discontinue hedge accounting for an existing hedge, prospectively and during the period the hedges became ineffective. In addition, for our new derivative contracts entered into after August 2007, we chose not to designate any of these contracts as cash flow hedges. As a result, any changes in fair value must be recorded in earnings under *Loss on derivatives not designated as hedges* and any related cash settlements are recorded to *Loss on derivatives not designated as hedges* . For the three months ended June 30, 2008, the related cash settlement payments for derivative instruments not designated as cash flow hedges was approximately $12.4 million. The non-cash mark-to-market adjustment for other derivative instruments not designated as cash flow hedges was a loss of $90.1 million.

Interest expense. Interest expense was $3.9 million for the three months ended June 30, 2008, a decrease of $6.2 million from $10.1 million for the three months ended June 30, 2007. The weighted average interest rate for the three months ended June 30, 2008 and 2007 was 4.9% and 7.8%, respectively. The weighted average debt balance during the three months ended June 30, 2008 and 2007 was approximately $302.1 million and $454.4 million, respectively. The decrease in weighted average debt balance during the three months ended June 30, 2008 was due to the partial prepayment in August 2007 of $86.6 million on the New 2nd Lien Credit Facility and the repayment in August 2007 of $86.6 million on the 1st Lien Credit Facility as well as partial prepayment in March 2008 on the 1st Lien Credit Facility utilizing cash from operations. The decrease in interest expense is due to a decrease in the weighted average interest rate and the decrease in the weighted average debt. In March 2007, we reduced the 1st Lien Credit Facility borrowing base by $100.00 million, or 21%, resulting in accelerated deferred loan cost amortization of $0.77 million, and the full repayment of the 2nd Lien Credit Facility resulting in accelerated deferred loan cost amortization of $0.43 million.

Income tax provisions. We recorded an income tax benefit of $9.2 million and income tax expense of $4.0 million for the three months ended June 30, 2008 and 2007, respectively. The effective income tax rate for the three months ended June 30, 2008 and 2007 was 38.9% and 40.2%, respectively.

Six months ended June 30, 2008, compared to six months ended June 30, 2007

Oil and gas revenues. Revenue from oil and gas operations was $244.1 million for the six months ended June 30, 2008, an increase of $117.7 million (93%) from $126.4 million for the six months ended June 30, 2007. This increase was primarily because of increased production due to successful drilling efforts during 2008 coupled with substantial increases in realized oil and gas prices. In addition:

average realized oil prices (after giving effect to hedging activities) were $95.87 per Bbl during the six months ended June 30, 2008, an increase of 67% from $57.33 per Bbl during the six months ended June 30, 2007;

total oil production was 1,786 MBbl for the six months ended June 30, 2008, an increase of 348 MBbl (24%) from 1,438 MBbl for the six months ended June 30, 2007;

average realized natural gas prices (after giving effect to hedging activities) were $11.30 per Mcf during the six months ended June 30, 2008, an increase of 52% from $7.45 per Mcf during the six months ended June 30, 2007;

total natural gas production was 6,451 MMcf for the six months ended June 30, 2008, an increase of 546 MMcf (9%) from 5,905 MMcf for the six months ended June 30, 2007;

average realized natural gas equivalent prices (after giving effect to hedging activities) were $14.22 per Mcfe during the six months ended June 30, 2008, an increase of 63% from $8.70 per Mcfe during the six months ended June 30, 2007; and

total production was 17,167 MMcfe for the six months ended June 30, 2008, an increase of 2,631 MMcfe (18%) from 14,536 MMcfe for the six months ended June 30, 2007.

See discussion in Recent events about 2007 and 2008 production interruptions due to plant and refinery shut-downs.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. The following is a summary of the effects of commodity hedges for the six months ended June 30, 2008 and 2007:

	Crude Oil Hedges Six months ended June 30, (unaudited)		Natural Gas Hedges Six months ended June 30, (unaudited)	
	2008	2007	2008	2007
Hedging revenue increase (decrease)	$(20,573,000)	$244,000	$ (222,000)	$ 187,000
Hedged volumes (Bbls and MMBtus, respectively)	473,000	534,000	2,457,000	3,152,000
Hedged revenue increase (decrease) per hedged volume	$ (43.49)	$ 0.46	$ (0.09)	$ 0.06

During the six months ended June 30, 2008, our commodity price hedges decreased oil revenues by $20.6 million ($11.52 per Bbl). During the six months ended June 30, 2007, our commodity price hedges increased oil revenues by $0.2 million ($0.17 per Bbl). The effect of the commodity price hedges in decreasing oil revenues during the six months ended June 30, 2008 compared to their effect of decreasing oil revenues during the six months ended June 30, 2007 was the result of (1) a higher average market price of NYMEX crude oil of $110.98 per Bbl in 2008 as compared to $61.70 per Bbl in 2007 and (2) the greater price difference between NYMEX and the weighted average hedge price in 2008 as compared to 2007, partially offset by a lower amount of hedged volumes of 473,000 Bbls in 2008 as compared to 534,000 Bbls in 2007.

During the six months ended June 30, 2008, our commodity price hedges decreased gas revenues by $0.2 million ($0.03 per Mcf) as a result of the amount reclassified from *AOCI* into natural gas revenues from cash flow hedges that were dedesignated as of June 30, 2007. Cash settlements for these dedesignated natural gas contracts are being recorded to *(Gain) loss on derivatives not designated as hedges*. During the six months ended June 30, 2007, our commodity price hedges increased gas revenues by $0.2 million ($0.03 per Mcf) as a result of the price difference between the market reference price of natural gas and the commodity contract price.

Production expenses. Production expenses (including production taxes) were $38.9 million ($2.26 per Mcfe) for the six months ended June 30, 2008, an increase of $14.7 million (61%) from $24.2 million ($1.66 per Mcfe) for the six months ended June 30, 2007. The increase in production expenses is due to: (1) production expenses associated with new wells that were successfully completed in 2008 as a result of our drilling activities and (2) an increase in production taxes as discussed below. Lease operating expenses and workover costs comprised approximately 46% and 59% of production expenses for the six months ended June 30, 2008 and 2007, respectively. These costs per unit of production were $1.03 per Mcfe during the six months ended June 30, 2008, an increase of 6% from $0.98 per Mcfe during the six months ended June 30, 2007. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 6% and 7% of lease operating expenses for the six months ended June 30, 2008 and 2007, respectively.

The secondary component of production expenses is production taxes, which is directly related to commodity price changes. These costs comprised approximately 54% and 41% of production expenses during the six months ended June 30, 2008 and 2007, respectively. Production taxes per unit of production were $1.23 per Mcfe during the six months ended June 30, 2008, an increase of 80% from $0.68 per Mcfe during the six months ended June 30, 2007. This increase was primarily due to an increase in average natural gas equivalent prices we received.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the six months ended June 30, 2008 and 2007:

	Six months ended June 30,	
	2008	2007
(in thousands)	(unaudited)	
Geological and geophysical	$2,316	$ 624
Exploratory dry holes		5,665
Leasehold abandonments and other	1,148	16
Total exploration and abandonments	$3,464	$6,305

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, during the six months ended June 30, 2008 was $2.3 million, an increase of $1.7 million from $0.6 million for the six months ended June 30, 2007. This increase is primarily attributable to a comprehensive seismic survey on our New Mexico shelf properties which was initiated in December 2007.

Our exploratory dry holes expense during the six months ended June 30, 2007 was primarily attributable to three operated exploratory wells that were unsuccessful. The costs associated with one of these wells drilled in the Western Delaware Basin in Culberson County, Texas approximated $2.8 million. Another of these wells, which was drilled in the Southeastern New Mexico Basin in Lea County, New Mexico, had costs of approximately $2.0 million. An additional $0.8 million was charged to exploratory dry hole costs relative to a target zone in the third of these wells in the Southeastern New Mexico Basin in Eddy County, New Mexico which was determined to be dry. This well was completed in a shallower zone which was found to be productive.

For the six months ended June 30, 2008, we recorded $1.1 million of leasehold abandonments, which are primarily related to prospects in Chaves and Eddy Counties, New Mexico and Andrews and Crane Counties, Texas. We had minimal leasehold abandonments during the six months ended June 30, 2007.

Depreciation and depletion expense. Depreciation and depletion expense was $43.3 million ($2.52 per Mcfe), including $42.5 million associated with oil and gas properties ($2.48 per Mcfe), for the six months ended June 30, 2008, an increase of $6.3 million from $37.0 million ($2.55 per Mcfe), including $36.6 million associated with oil and gas properties ($2.51 per Mcfe), for the six months ended June 30, 2007. The increase in depreciation and depletion expense was primarily due to capitalized costs associated with new wells that were successfully completed in 2007 and 2008 as a result of our drilling activities. The decrease in depreciation and depletion expense per Mcfe was primarily due to an increase in proved oil and natural gas reserves as a result of our successful development and exploratory drilling program as well as an increase of commodity prices utilized for the reserve estimates, partially offset by increased production. The crude oil price utilized for our estimate of proved oil and gas reserves was $136.50 as of June 30,

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2008, an increase of $69.25 (103%) from $67.25 as of June 30, 2007. The natural gas price utilized for our estimate of proved oil and gas reserves was $13.10 as of June 30, 2008, an increase of $6.30 (93%) from $6.80 as of June 30, 2007.

Impairment of oil and gas properties. In accordance with SFAS No. 144, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets during the six months ended June 30, 2008, we recognized a non-cash charge against earnings of $0.1 million, which was comprised primarily of a wells drilled on acreage in Eddy County, New Mexico and Lea County, New Mexico. For the six months ended June 30, 2007, we recognized a non-cash charge against earnings of $3.2 million, 63% of which related to a well drilled on acreage in Schleicher County, Texas, and 12% of which related to a well drilled on acreage in Mountrail County, North Dakota.

Contract drilling fees stacked rigs. As discussed in our Annual Report on Form 10-K for the year ended December 31, 2007, we determined in January 2007 to reduce our drilling activities for the first three months of 2007. As a result, we recorded an expense during the six months ended June 30, 2007 of approximately $4.3 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007. These costs were minimized during the first six months of 2007 as one contractor secured work for a rig for 71 days during that period and charged us only the difference between the then-current operating day rate pursuant to the contract and the lower operating day rate received from the new customer.

General and administrative expenses. General and administrative expenses were $16.3 million ($0.95 per Mcfe) for the six months ended June 30, 2008, an increase of $4.4 million (37%) from $11.9 million ($0.82 per Mcfe) for the six months ended June 30, 2007. Included in general and administrative expense was non-cash stock-based compensation of $3.0 million during the six months ended June 30, 2008 and $2.0 million during the six months ended June 30, 2007. General and administrative expenses, excluding non-cash stock-based compensation, (Net general expense) were $13.2 million ($0.77 per Mcfe) for the six months ended June 30, 2008, an increase of $3.2 million (32%) from $10.0 million ($0.69 per Mcfe) for the six months ended June 30, 2007. The increase in Net general expenses during the six months ended June 30, 2008 was primarily due to an increase in the number of employees and related personnel expenses.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $0.5 million and $0.6 million during the six months ended June 30, 2008 and 2007, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Bad debt expense. On May 20, 2008, we entered into a temporary purchase agreement with an oil purchaser to buy a portion of the oil affected as a result of the New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared Chapter 11 bankruptcy in a Delaware federal bankruptcy court. We fully reserved the receivable amount due from this purchaser of approximately $1.8 million as of June 30, 2008.

Loss on derivatives not designated as cash flow hedges. As explained in *Hedging activities*, during the three months ended September 30, 2007, we determined that all of our natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133. If the hedge is no longer highly effective, according to SFAS No. 133, an entity shall discontinue hedge accounting for an existing hedge, prospectively and during the period the hedges became ineffective. In addition, for our new derivative contracts entered into after August 2007, we chose not to designate any of these contracts as cash flow hedges. As a result, any changes in fair value must be recorded in earnings under *Loss on derivatives not designated as hedges* and any related cash settlements are recorded to *Loss on derivatives not designated as hedges* . For the six months ended June 30, 2008, the related cash settlement payments for derivative instruments not designated as cash flow hedges was approximately $16.4 million. The non-cash mark-to-market adjustment for other derivative instruments not designated as cash flow hedges was a loss of $103.2 million.

Interest expense. Interest expense was $9.5 million for the six months ended June 30, 2008, a decrease of $11.2 million from $20.7 million for the six months ended June 30, 2007. The weighted average interest rate for the six months ended June 30, 2008 and 2007 was 5.8% and 7.8%, respectively. The weighted average debt balance during the six months ended June 30, 2008 and 2007 was approximately $313.3 million and $501.3 million, respectively. The decrease in weighted average debt balance during the six months ended June 30, 2008 was due to the partial prepayment in August 2007 of $86.6 million on the New 2nd Lien Credit Facility and the repayment in August 2007 of $86.6 million on the 1st Lien Credit Facility as well as partial prepayment in March 2008 on the 1st Lien Credit Facility utilizing cash from operations. The decrease in interest expense is due to a decrease in the weighted average interest rate and the decrease in the weighted average debt. In March 2007, we reduced the 1st Lien Credit Facility borrowing base by $100.0 million, or 21%, resulting in accelerated deferred loan cost amortization of $0.8 million, and the full repayment of the 2nd Lien Credit Facility resulting in accelerated deferred loan cost amortization of $0.4 million.

Income tax provisions. We recorded income tax expense of $5.2 million and $7.4 million for the six months ended June 30, 2008 and 2007, respectively. The effective income tax rate for the six months ended June 30, 2008 and 2007 was 39.6% and 41.1%, respectively.

We had a net deferred tax liability of $243.3 million and $245.57 million at June 30, 2008 and December 31, 2007, respectively. The net liability balance is primarily due to differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes related to the acquisition of the Chase Group Properties in February 2006. The net change is due to 2008 intangible drilling costs which are allowed by the Internal Revenue Service as deductions and are capitalized under generally accepted accounting principles in the United States of America, partially offset by an increase in deferred hedge losses.

Liquidity and capital resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facilities. We believe that funds from operating cash flows and our bank credit facilities should be sufficient to meet both our short-term working capital requirements and our 2008 exploration and development budget.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $162.9 million and $63.6 million for the six months ended June 30, 2008 and 2007, respectively. The increase in operating cash flows during the six months ended June 30, 2008 over 2007 was principally due to increases in our oil and gas production as a result of our exploration and development program and increases in average realized oil and natural gas prices.

Cash Flow Used in Investing Activities

During the six months ended June 30, 2008 and 2007, we invested $122.8 million and $70.1 million, respectively, for additions to, and acquisitions of, oil and gas properties, inclusive of dry hole costs. Cash flows used in investing activities were substantially higher during the six months ended June 30, 2008, primarily due to increased drilling activity in 2008. In order to preserve liquidity, we reduced our drilling activities and curtailed capital expenditures during the six months ended June 30, 2007, until we were able to complete our second lien term loan facility in March 2007.

Cash Flow from Financing Activities

Net cash used in financing activities was $19.5 million for the six months ended June 30, 2008 and net cash provided by financing activities was $16.3 million for the six months ended June 30, 2007. During the six months ended June 30, 2008, we reduced our outstanding balance by $26.0 million on our 1st Lien Credit Facility utilizing cash from operations. In March 2007, we entered into a $200.0 million second lien term loan facility. The proceeds were principally used to repay the outstanding balance under our prior term loan facility and to reduce the outstanding balance under our 1st Lien Credit Facility.

Bank Credit Facilities

We have two separate bank credit facilities. The first is our credit facility agreement, dated February 24, 2006, with JPMorgan Chase Bank, N.A. as the administrative agent for a group of lenders that provides a revolving line of credit having a total commitment of $550.0 million, which we refer to as our 1st Lien Credit Facility. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of the total commitment of $550.0 million or the borrowing base established by the lenders. Various amendments have redetermined the borrowing base under the 1st Lien Credit Facility, which was $550.0 million as of June 30, 2008. The amount outstanding under the 1st Lien Credit Facility at June 30, 2008 was $190.0 million.

The second bank credit facility is our term loan agreement, dated March 27, 2007, with Bank of America, N.A., as the administrative agent for the other lenders thereunder, that provides a five year term loan in the amount of $200.0 million, the New 2nd Lien Credit Facility. Upon execution of the New 2nd Lien Credit Facility, we funded the full amount under that facility and received net proceeds of $199.0 million to repay the $39.8 million outstanding under our 2nd Lien Credit Facility, to reduce the outstanding balance under our 1st Lien Credit Facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes. We used net proceeds of approximately $173.0 million from our initial public offering that was completed in August 2007 to retire outstanding borrowings under our New 2nd Lien Credit Facility totaling $86.5 million and to retire outstanding borrowings under our 1st Lien Credit Facility totaling $86.5 million.

1st Lien Credit Facility. The 1st Lien Credit Facility allows us to borrow, repay and reborrow amounts available under the borrowing base. The amount of the borrowing base is based primarily upon the estimated value of our oil and natural gas reserves. The borrowing base under our 1st Lien Credit Facility is re-determined at least semi-annually. The 1st Lien Credit Facility matures on

February 24, 2011, and borrowings bear interest, payable quarterly, at our option, at (1) a rate (as defined and further described in our revolving credit facility) per annum equal to a Eurodollar Rate (which is substantially the same as the London Interbank Offered Rate) for one, two, three or six months as offered by the lead bank under our 1st Lien Credit Facility, plus an applicable margin ranging from 125 275 basis points, or (2) such bank s Prime Rate, plus an applicable margin ranging from 0 to 125 basis points, dependent in each case upon the percentage of our available borrowing base then utilized. Our 1st Lien Credit Facility bore interest at 3.73% per annum as of June 30, 2008. We pay quarterly commitment fees under our 1st Lien Credit Facility on the unused portion of the available borrowing base ranging from 25 to 50 basis points, dependent upon the percentage of our available borrowing base then utilized.

Borrowings under our 1st Lien Credit Facility are secured by a first lien on substantially all of our assets and properties. Our 1st Lien Credit Facility also contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers involving our company, incur liens and engage in certain other transactions without the prior consent of the lenders. The 1st Lien Credit Facility also requires us to maintain certain ratios as defined and further described in our 1st Lien Credit Facility agreement, including a current ratio of not less than 1.0 to 1.0 and a maximum leverage ratio (generally defined as the ratio of total funded debt to a defined measure of cash flow) of no greater than 4.0 to 1.0. In addition, at the inception of the 1st Lien Credit Facility, we had a one-time requirement to enter into derivative contracts with respect to not less than 75% of our forecasted production through December 31, 2008, that was attributable to our proved developed producing reserves estimated as of December 31, 2005. As of June 30, 2008, we were in compliance with all such covenants.

New 2nd Lien Credit Facility. The New 2nd Lien Credit Facility provides a $200.0 million term loan, which bears interest, at our option, at (1) a rate per annum equal to the London Interbank Offered Rate, plus an applicable margin of 425 basis points or (2) the prime rate, plus an applicable margin of 275 basis points. We have the option to select different interest periods, subject to availability, and interest is payable at the end of the interest period we select, though such interest payments must be made at least on a quarterly basis. We are required to repay $0.5 million of the outstanding balance on the last day of each calendar quarter, commencing June 30, 2007, until the remaining balance of the loan matures on March 27, 2012. Our New 2nd Lien Credit Facility bore interest at 6.73% per annum as of June 30, 2008. We have the right to prepay the outstanding balance at any time, provided, however, that we will incur a 2% prepayment penalty on any principal amount prepaid from March 27, 2008 until March 26, 2009 and a 1% prepayment penalty on any principal amount prepaid from March 27, 2009 until March 26, 2010.

Borrowings under the New 2nd Lien Credit Facility are secured by a second lien on the same assets as are securing our 1st Lien Credit Facility, and are subordinated to liens securing our 1st Lien Credit Facility. The New 2nd Lien Credit Facility also contains various restrictive financial covenants and compliance requirements that are similar to those contained in the 1st Lien Credit Facility, including the maintenance of certain financial ratios. As of June 30, 2008, we were in compliance with all such covenants.

Amended and Restated Credit Facility

As of July 31, 2008, we amended and restated our Senior Credit Facility in various respects including, increasing the borrowing base to $960 million, subject to semiannual redetermination, and extending the maturity date from February 24, 2011 to July 31, 2013 (the Senior Credit Facility, as defined above). The initial borrowing under the Senior Credit Facility was $675 million. We paid an arrangement fee of $14.4 million at the date of closing of the Senior Credit Facility. This fee is being amortized to *Interest expense* over the remaining five year term of the facility beginning in August 2008.

Advances on the Senior Credit Facility bear interest, at our option, based on (a) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (5.00 percent at July 31, 2008) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 125 - 275 basis points and 0 - 125 basis points, respectively, per annum depending on the balance outstanding. We pay commitment fees on the unused portion of the available borrowing base ranging from 25 - 50 basis points per annum.

The Senior Credit Facility also includes a same-day advance facility under which we may borrow funds on a daily basis from the 1st Lien Banks administrative agent. Advances made on this same-day basis cannot exceed $25 million and the maturity dates cannot exceed fourteen days. The interest rate on this facility is the JPM Prime Rate plus the applicable interest margin.

Our obligations under the Senior Credit Facility are secured by a first lien on substantially all of our oil and gas properties. In addition, all of our subsidiaries are guarantors, and all subsidiary general partner, limited partner and membership interests owned by us have been pledged to secure borrowings under the Senior Credit Facility. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses no greater than 4.0 to 1.0, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations, to be no less than 1.0 to 1.0;

(b) limits on the incurrence of additional indebtedness and certain types of liens; (c) restrictions as to merger and sale or transfer of assets; and (d) a restriction on the payment of cash dividends.

Future Capital Expenditures and Commitments

On August 7, 2008, our board of directors approved an increase in our 2008 exploration and development budget in the amount of $71.1 million from the amended budget of $318.2 million to $389.3 million. Our 2008 capital budget is comprised of the following:

(in millions)	**Original Budget**	**Revised Budget**
Drilling and recompletion opportunities in our core operating area	$209.5	$310.8
Projects operated by third parties	14.3	14.3
Emerging plays, acquisition of leasehold acreage and other property interests, and geological and geophysical	20.0	57.6
Maintenance capital in our core operating areas	6.6	6.6
Total 2008 exploration and development budget	$250.4	$389.3

We anticipate that this incremental $71.1 million in our 2008 exploration and development budget will be funded primarily by cash flow from operations.

Other than leasehold acreage and other property interests shown above, our 2008 exploration and development budget is exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and gas properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations and that will allow us to apply our operating expertise or that otherwise have geologic characteristics that are similar to our existing properties.

On July 31, 2008, we closed the acquisition of Henry (the Acquisition), as defined above. Cash paid at closing totaled approximately $560 million. We financed the Acquisition with proceeds raised from a $250.0 million private placement of 8.3 million shares of our common stock, together with funds available under the Senior Credit Facility. After the closing of the Acquisition and the additional interests acquired concurrently as described below, we have approximately $285 million of availability under the Senior Credit Facility.

In connection with the Acquisition, we also purchased certain additional non-operated rights and interests in Henry s oil and gas properties from the Along-side Transactions for aggregate cash consideration of approximately $28.0 million.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance and cash flows from operations will be sufficient to satisfy our 2008 exploration and development budget; however, we could use our revolving credit facility to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. In addition, under certain circumstances we would consider increasing or reallocating our 2008 capital budget.

Commodity Derivatives and Hedging

On March 3, 2008, we entered into two crude oil price swaps to hedge an additional portion of our estimated crude oil production for calendar years 2008 and 2009. The contracts are for 1,400 Bbls per day for the remainder of 2008 (April through December) at a fixed price of $99.25 per Bbl, and 800 Bbls per day for calendar year 2009 at a fixed price of $98.35 per Bbl. We have not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments will be recorded each period to *(Gain) loss on derivatives not* *designated as hedges.*

On March 11, 2008, we entered into a natural gas price swap to hedge an additional portion of our estimated natural gas production for calendar year 2009. The contract is for 5,000 MMBtus per day with a fixed price of $8.44. We have not designated this derivative instrument as a cash flow hedge. Mark-to-market adjustments related to this derivative instrument will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

On June 5, 2008, the Company entered into a crude oil costless collar to hedge a portion of its estimated crude oil production for calendar year 2009. The contract is for 64,000 Bbls per month (or 2,104 Bbls per day) for calendar year 2009 with a ceiling of $134.60

per Bbl and a floor of $120.00 per Bbl. The Company has not designated this derivative instrument as a cash flow hedge. Mark-to-market adjustments related to this derivative instrument will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

On June 6, 2008, the Company entered into three crude oil price swaps to hedge a portion of its estimated crude oil production for calendar years 2010, 2011 and 2012.

As of June 30, 2008, we have oil price swaps and collars that settle on a monthly basis covering future oil production from July 1, 2008 through December 31, 2012. The volumes are detailed in the table below. Subsequent to June 30, 2008, oil futures prices have decreased; however, they continue to exceed the weighted average swap fixed price and collar ceiling price of $97.60 for all oil contracts and $77.67 for oil contracts settling in 2008. The average NYMEX oil futures price for the quarter ended June 30, 2008, was $124.28. As of August 7, 2008, the NYMEX oil futures price was $120.02. At this pricing level, for each monthly settlement period, we will continue to remit the excess of the monthly average NYMEX oil futures price for each settlement period over the weighted average swap fixed price and collar ceiling price from above. These payments to the counterparties could significantly affect our cash flow but the impact should be reduced or partially offset by (1) increased commodity prices received on the sale of our unhedged oil production and (2) only a portion of the total remaining contract volume settles each month. The decrease in oil prices, should it continue through the end of the third quarter of 2008, should increase the fair value of our commodities contracts from their recorded balance at June 30, 2008. Changes in the recorded fair value of the undesignated commodity derivatives are marked to market through earnings as unrealized gains or losses. The potential increase in fair value would be recorded in earnings as unrealized gains. However, an increase in the average NYMEX oil futures price above the second quarter average would result in a decrease in fair value and unrealized losses in earnings. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our derivative contracts.

The table below provides the volumes and related data associated with our oil and natural gas derivatives as of June 30, 2008:

	Fair Market Value Liability (in thousands)	Aggregate remaining volume	Daily volume	Index price	Contract period
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	$ (34,958)	478,400	2,600	$67.50 (a)	7/1/08 - 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	(7,348)	2,484,000	13,500	$6.50 - $9.35 (b)	7/1/08 - 12/31/08
Derivatives not designated as cash flow hedges:					
Crude oil (volumes in Bbls):					
Price collar	(8,578)	768,000	2,104	$120.00 - $134.60 (a)	1/1/09 - 12/31/09
Price swap	(34,558)	625,600	3,400	$85.44 (a) (c)	7/1/08 - 12/31/08
Price swap	(60,264)	1,022,000	2,800	$80.13 (a) (c)	1/1/09 - 12/31/09
Price swap	(2,182)	240,000	658	$128.80 (a)	1/1/10 - 12/31/10

Price swap		(2,522)	336,000	921	$128.66 [(a)]	1/1/11 - 12/31/11
Price swap		(3,785)	504,000	1,377	$127.80 [(a)]	1/1/12 - 12/31/12
Natural gas (volumes in MMBtus):						
Price swap		(5,133)	1,825,000	5,000	$8.44 [(b)]	1/1/09 - 12/31/09
Net liability	$	(159,328)				

(a) The index prices for the oil price swaps are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index price for the natural gas price collar is based on the Inside FERC-El Paso Permian Basin first-of-the-month spot price.

(c) Amounts disclosed represent weighted average prices.

Valuation of Derivative Instruments

We measure our derivative instruments at fair value. Both realized and unrealized gains or losses from derivative instruments are reflected in *Oil and natural gas sales* and *Loss on derivatives not designated as hedges* in the consolidated statements of operations.

We adopted SFAS No. 157, Fair Value Measurements (SFAS No. 157), in the first quarter of 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the inputs used to measure fair value and enhances disclosure requirements for fair value measurements.

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or an exit price. The degree of judgment utilized in measuring the fair value of derivative instruments generally correlates to the level of pricing observability. Derivative instruments with readily available active quoted prices or for which fair value can be measured from actively quoted prices in active markets generally have more pricing observability and less judgment utilized in measuring fair value. Conversely, derivative instruments rarely traded or not quoted have less observability and are measured at fair value using valuation models that require more judgment. Pricing observability is impacted by a number of factors, including the type of derivative instrument, whether the derivative instrument is new to the market and not yet established, the characteristics specific to the transaction and overall market conditions generally.

The overall valuation process for derivative instruments may include adjustments to valuations derived from pricing models. These adjustments may be made when, in management s judgment, either the size of the position in the derivative instrument or other features of the derivative instrument such as its complexity, or the market in which the derivative instrument is traded (such as counterparty, credit, concentration or liquidity) require that an adjustment be made to the value derived from the pricing models. An adjustment may be made if the sale of a derivative instrument is subject to sales restrictions that would result in a price less than the computed fair value measurement from a quoted market price. Additionally, an adjustment from the price derived from a model typically reflects management s judgment that other participants in the market for the derivative instrument being measured at fair value would also consider such an adjustment in pricing that same derivative instrument.

We have categorized our derivative instruments measured at fair value into a three-level classification in accordance with SFAS No. 157. Fair value measurements of derivative instruments that use quoted prices in active markets for identical assets or liabilities are generally categorized as Level 1, and fair value measurements of derivative instruments that have no direct observable levels are generally categorized as Level 3. The lowest level input that is significant to the fair value measurement of a derivative instrument is used to categorize the instrument and reflects the judgment of management. Derivative assets and liabilities presented at fair value in our consolidated balance sheet generally are categorized as follows:

Level 1 Inputs are unadjusted, quoted prices in active markets for identical, unrestricted assets or liabilities at the measurement date.

Level 2 Inputs (other than quoted prices included in Level I) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument s anticipated life.

Generally, assets and liabilities carried at fair value included in this category are commodity price swaps.

Level 3 Inputs reflect management s best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

Generally, assets and liabilities carried at fair value included in this category are commodity price collars.

Derivative assets and liabilities presented at fair value and categorized as Level 3 are generally those that are marked to model using relevant empirical data to extrapolate an estimated fair value. The models inputs reflect assumptions that market participants would use in pricing the instrument in a current period transaction and outcomes from the models represent an exit price and expected future cash flows. Valuation models are calibrated to the market on a frequent basis.

The parameters and inputs are adjusted for assumptions about risk and current market conditions. Changes to inputs in valuation models are not changes to valuation methodologies; rather, the inputs are modified to reflect direct or indirect impacts on asset classes from changes in market conditions. Accordingly, results from valuation models in one period may not be indicative of future period measurements.

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The following table presents comparative metrics of the Company s Level 3 liabilities at June 30, 2008 and December 31, 2007:

(in thousands)	June 30, 2008	December 31, 2007
Level 3 derivative assets	$	$ 1,866
Less: Level 3 derivative liabilities	(15,926)	
Level 3 net derivative assets (liabilities)	$ (15,926)	$ 1,866
Total assets (liabilities)	$(850,274)	$1,508,229
Total derivative assets measured at fair value	$	$ 1,866
Less: Total derivative liabilities measured at fair value	(159,328)	(46,931)
Net derivative assets (liabilities) measured at fair value	$(159,328)	$ (45,065)
Level 3 derivative assets (liabilities) as a percent of total assets (liabilities)	2%	0%
Level 3 derivative assets (liabilities) as a percent of total derivative assets (liabilities) measured at fair value	10%	100%
Level 3 net derivative assets (liabilities) as a percent of net derivative assets (liabilities) measured at fair value	10%	4%

For a further discussion regarding the measurement of derivative instruments at fair value, see Note D *Fair Value Measurements,* to the consolidated financial statements.

Contractual obligations and commitments

We had the following material changes in our contractual obligations and commitments as of June 30, 2008:

		Payments due by period			
(in thousands)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Employment agreements with executive officers [(a)]	2,562	2,008	554		

(a) Represents amounts of cash compensation we are obligated to pay to our executive officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

Effective March 1, 2008, Messrs. Leach and Beal each received an annual pay increase of $100,000.

An executive officer resigned as of March 31, 2008, and the Company will be obligated to pay such person 1/12th of his base salary for each month from April 2008 through March 2009 as consideration for such person s covenant not to compete with the Company in accordance with his employment agreement.

Effective May 21, 2008, the Board of Directors appointed Matthew G. Hyde Vice President Exploration and entered into an employment agreement with him.

An executive officer resigned as of June 23, 2008. The Company is no longer obligated to pay such person as the non-compete clause of his employment agreement was not executed by the Board of Directors. As such, his annual salary is no longer included in the table above.

Off-balance sheet arrangements

Currently we do not have any off-balance sheet arrangements.

Critical accounting policies and practices

Our historical consolidated financial statements and notes to our historical consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations and impairment of assets. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

There have been no material changes in our critical accounting policies and procedures during the six months ended June 30, 2008. See our disclosure of critical accounting policies in the consolidated financial statements on our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on March 28, 2007.

Recent accounting pronouncements

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115, which will become effective in 2008. SFAS No. 159 permits entities to measure eligible financial assets, financial liabilities and firm commitments at fair value, on an instrument-by-instrument basis, that are otherwise not permitted to be accounted for at fair value under other generally accepted accounting principles. The fair value measurement election is irrevocable and subsequent changes in fair value must be recorded in earnings. We adopted this statement January 1, 2008 and did not elect the fair value option for any of its eligible financial instruments or other items. As such, the adoption had no impact on the consolidated financial statements.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, Amendment of FASB Interpretation No. 39 (FIN No. 39-1). FIN No. 39-1 clarifies that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement. FIN No. 39-1 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Adoption of FIN No. 39-1 has not had a material impact on our consolidated financial statements.

In June 2007, the FASB ratified a consensus opinion reached by the Emerging Issues Task Force (EITF) on EITF Issue 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. EITF Issue 06-11 requires an employer to recognize tax benefits realized from dividend or dividend equivalents paid to employees for certain share-based payment awards as an increase to additional paid-in capital and include such amounts in the pool of excess tax benefits available to absorb future tax deficiencies on share-based payment awards. If an entity s estimate of forfeitures increases (or actual forfeitures exceed the entity s estimates), or if an award is no longer expected to vest, entities should reclassify the dividends or dividend equivalents paid on that award from retained earnings to compensation cost. However, the tax benefits from dividends that are reclassified from additional paid-in capital to the income statement are limited to the entity s pool of excess tax benefits available to absorb tax deficiencies on the date of reclassification. The consensus in EITF Issue 06-11 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2007. Retrospective application of EITF Issue 06-11 is not permitted. Early adoption is permitted; however, we did not adopt EITF Issue 06-11 until the required effective date of January 1, 2008. The adoption of EITF Issue 06-11 has not had a significant effect on our financial statements since we historically have accounted for the income tax benefits of dividends paid for share-based payment awards in the manner described in the consensus.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141(R)), which replaces FASB Statement No. 141. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non- controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be our fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51. SFAS No. 160 requires that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS No. 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008, which will be our fiscal year 2009. Based upon our June 30, 2008 balance sheet, the statement would have no impact.

In December 2007, the SEC issued Staff Accounting Bulletin (SAB) No. 110, Share-Based Payment (SAB No. 110). SAB No. 110 amends SAB No. 107, Share-Based Payment, and allows for the continued use, under certain circumstances, of the simplified method in developing an estimate of the expected term on stock options accounted for under SFAS No. 123R, Share-Based Payment (revised 2004). SAB No. 110 is effective for stock options granted after December 31, 2007. We continued to use the simplified method in developing an estimate of the expected term on stock options granted in the first and second quarters of 2008. We do not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time our shares of common stock have been publicly traded.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities (SFAS No. 161), which amends and expands the disclosure requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), to provide an enhanced understanding of an entity s use of derivative instruments, how they are accounted for under SFAS No. 133 and their effect on the entity s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective as of January 1, 2009. We are currently evaluating the impact on our consolidated financial statements of adopting SFAS No. 161.

Cautionary statement regarding forward-looking statements

This report may contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this quarterly report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this quarterly report, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potent similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and detailed in our Annual Report on Form 10-K for the year ended December 31, 2007, could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

§ business strategy;

§ estimated quantities of oil and natural gas reserves;

§ technology;

§ financial strategy;

§ oil and natural gas realized prices;

§ timing and amount of future production of oil and natural gas;

§ the amount, nature and timing of capital expenditures;

§ drilling of wells;

§ competition and government regulations;

§ marketing of oil and natural gas;

§ exploitation or property acquisitions;

§ costs of exploiting and developing our properties and conducting other operations;

- § general economic and business conditions;
- § cash flow and anticipated liquidity;
- § uncertainty regarding our future operating results; and
- § plans, objectives, expectations and intentions contained in this quarterly report that are not historical.

You should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this quarterly report. We do not undertake any obligation to release publicly any revisions to the forward-looking statements to reflect events or circumstances after the date of this quarterly report or to reflect the occurrence of unanticipated events except as required by law.

Although we believe that our plans, objectives, expectations and intentions reflected in or suggested by the forward-looking statements we make in this quarterly report are reasonable, we can give no assurance that they will be achieved. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 3. **QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our Annual Report on Form 10-K for the year ended December 31, 2007, as well as with the consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments.

Hypothetical changes in interest rates and prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries, as described under Item 1. Business Marketing Arrangements in our Annual Report on Form 10-K for the year ended December 31, 2007. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligation to us, we may, if circumstances dictate, require collateral in the future.

Commodity price risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of oil and natural gas we have entered into, and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our common stock. As of June 30, 2008, the net unrealized loss on our commodity price risk management contracts was $159.3 million. An average increase in the commodity price of $1.00 per barrel of crude oil and $0.10 per Mcf for natural gas from the commodity prices as of June 30, 2008, would have resulted in an increase in the net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet as of June 30, 2008, of approximately $4.1 million.

At June 30, 2008, we have an oil price collar and oil price swaps that settle on a monthly basis covering future oil production from July 1, 2008 through December 31, 2012. See Commodity Derivatives and Hedging. Subsequent to June 30, 2008, oil futures prices have decreased; however, they continue to exceed the weighted average swap fixed price and collar ceiling price of $97.60 for all oil contracts and $77.67 for oil contracts settling in 2008. The average NYMEX oil futures price for the quarter ended June 30, 2008, was $124.28. As of August 7, 2008, the NYMEX oil futures price was $120.02. At this pricing level, for each monthly settlement period, we will continue to remit the excess of the monthly average NYMEX oil futures price for each settlement period over the weighted average swap fixed price and collar ceiling price from above. These payments to the counterparties could significantly affect our cash flow but the impact should be reduced or partially offset by (1) increased commodity prices received on the sale of our unhedged oil production and (2) only a portion of the total remaining contract volume settles each month. The decrease in oil prices, should it continue through the end of the third quarter of 2008, should increase the fair value of our commodities contracts from their recorded balance at June 30, 2008. Changes in the recorded fair value of the undesignated commodity derivatives are marked to market through earnings as unrealized gains or losses. The potential increase in fair value would be recorded in earnings as unrealized gains. However, an increase in the average NYMEX oil futures price above the second quarter average would result in a decrease in fair value and unrealized losses in earnings. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our derivative contracts.

Interest rate risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our bank credit facilities, and the terms of our revolving credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. We had total indebtedness of $190.0 million outstanding under our revolving credit facility at June 30, 2008. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.9 million and a corresponding decrease in net income before income tax. As of June 30, 2008, we had $111.4 million of outstanding indebtedness under our 2nd Lien Credit Facility. The impact of a 1% increase in interest rates on this amount of debt under our second lien term loan facility would result in increased interest expense of approximately $1.1 million and a corresponding decrease in net income before income tax.

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Item 4. CONTROLS AND PROCEDURES

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this quarterly report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Our Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2008, our disclosure controls and procedures were effective, in all material respects, to ensure that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

We have begun taking steps to comprehensively document and analyze our system of internal controls. We plan to continue this initiative as well as prepare for our first management report on internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002, prior to its applicability to us in connection with our filing of our Annual Report on Form 10-K for the year ending December 2008. In that regard, we have made and expect to continue to make changes in our internal controls over financial reporting. Although these changes may continue to improve our internal controls, there were no changes in our internal controls over financial reporting that occurred during the period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Period	Total number of shares purchased[(1)]	Average price paid per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
April 1, 2008 - April 30, 2008		$		
May 1, 2008 - May 31, 2008		$		
June 1, 2008 - June 30, 2008	3,142	$ 39.78		

(1) Represents shares that were withheld by the Company to satisfy tax withholding obligations that arose upon the lapse of restrictions on restricted stock.

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

The 2008 Annual Meeting of Stockholders of Concho Resources Inc. (Annual Meeting) was held on June 17, 2008, in Midland, Texas for the following purposes: (i) to elect three Class I directors, each for a term of three years; (ii) to ratify the Audit Committee of the Board of Directors selection of Grant Thornton LLP as the independent registered public accounting firm of the Company for the fiscal year ending December 31, 2008; and (iii) to transact such other business as may properly come before the Annual Meeting or any adjournments or postponements thereof.

Proxies for the Annual Meeting were solicited by the Board pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended and there was no solicitation in opposition to the Board s nominees for director.

Each of the nominees for director was duly elected, with votes as follows:

Nominee	Shares for	Shares withheld
Timothy A. Leach	65,024,406	634,794
William H. Easter III	65,611,891	47,309
W. Howard Keenan, Jr.	65,611,955	47,245

The appointment of Grant Thornton LLP, independent public accountants, as the Company s auditors for the year ending December 31, 2008, was ratified by the Company s stockholders by the following vote: 65,591,133 for; 60,644 shares against,; and 7,423 shares abstaining.

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Item 6. Exhibits

Exhibit Number	Exhibit
10.1	Third Amendment to Credit Agreement, dated as of May 19, 2008 by and among Concho Resources Inc., certain of its subsidiaries, JPMorgan Chase Bank, N.A. and other lenders party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on May 23, 2008 and incorporated herein by reference).
10.2	Indemnification Agreement, dated May 21, 2008, by and between Concho Resources Inc. and Matthew G. Hyde (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on May 28, 2008, and incorporated herein by reference).
10.3	Employment Agreement, dated May 21, 2008, by and between Concho Resources Inc. and Matthew G. Hyde (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on May 28, 2008, and incorporated herein by reference).
10.4	Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc., James C. Henry and Paula Henry, Henry Securities Ltd., Henchild LLC, Henry Family Investment Group, Henry Holding Lap, Henry Energy LP, Aguasal Holding, HELP Investment LLC, Henry Capital LLC, Henry Operating LLC, Henry Petroleum LP, Quail Ranch LLC, Aguasal Management LLC and Aguasal LP (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
10.5	Common Stock Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc. and the Purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
10.6	Registration Rights Agreement, dated July 31, 2008, by and between Concho Ressources Inc. and the Purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
10.7	Amended and Restated Credit Agreement, dated July 31, 2008, by and between Concho Resources Inc., JPMorgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 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.

	CONCHO RESOURCES INC.
Date: August 13, 2008	By /S/ Timothy A. Leach Timothy A. Leach Director, Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)
	By /S/ Steven L. Beal Steven L. Beal Director, President, Chief Operating Officer and Chief Financial Officer (Principal Financial and Accounting Officer)

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