CONCHO RESOURCES INC
Form 10-Q
November 14, 2007

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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 September 30, 2007

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 o No þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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 November 14, 2007: 75,750,730 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)	September 30, 2007	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 19,868	$ 1,122
Accounts receivable:		
Oil and gas	24,793	27,304
Joint operations and other	16,027	22,638
Related parties		1,449
Derivative instruments	1,658	6,013
Deferred income taxes	3,625	82
Inventory	1,404	1,309
Prepaid insurance and other	3,618	3,848
Total current assets	70,993	63,765
Property and equipment, at cost:		
Oil and gas properties, successful efforts method:		
Proved properties	1,266,890	1,159,756
Unproved properties	237,223	239,462
Accumulated depletion and depreciation	(142,981)	(84,098)
Total oil and gas properties, net	1,361,132	1,315,120
Other property and equipment, net	6,894	5,535
Total property and equipment, net	1,368,026	1,320,655
Deferred loan costs, net	3,737	4,417
Other assets	751	1,235
Total assets	$1,443,507	$1,390,072
Liabilities and stockholders equity		
Current liabilities:		
Accounts payable:		
Trade	$ 7,583	$ 16,157
Related parties	2,941	3,593
Other current liabilities:		
Revenue payable	4,576	9,901
Accrued drilling costs	27,633	17,051
Accrued interest	1,755	8,004
Other accrued liabilities	7,712	6,220
Derivative instruments	10,303	6,224
Dividends payable		87

Income taxes payable	225	
Chase Group unaccredited investors asset purchase obligation		906
Current portion of long-term debt	2,000	400
Current asset retirement obligations	1,005	1,958
Total current liabilities	65,733	70,501
Long-term debt	343,880	495,100
Noncurrent derivative instruments	1,514	
Deferred income taxes	251,800	241,752
Asset retirement obligations and other long-term liabilities	7,196	7,563
Commitments and contingencies (Note K)		
Stockholders equity:		
6% Series A preferred stock, $0.01 par value; 30,000,000 shares authorized; and zero shares issued and outstanding at September 30, 2007 and December 31, 2006		
Preferred stock, $0.001 par value; 10,000,000 shares authorized; and zero shares issued and outstanding at September 30, 2007 and December 31, 2006		
Common stock, $0.001 par value; 300,000,000 authorized; 75,750,517 and 59,092,830 shares issued and outstanding at September 30, 2007 and December 31, 2006, respectively	76	59
Additional paid-in capital	751,680	575,389
Notes receivable from officers and employees	(2,488)	(12,858)
Retained earnings	30,609	12,152
Accumulated other comprehensive income (loss)	(6,493)	414
Total stockholders equity	773,384	575,156
Total liabilities and stockholders equity	$1,443,507	$1,390,072

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

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Concho Resources Inc. and subsidiaries
Consolidated statements of operations
Unaudited

(in thousands, except per share amounts)	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
Operating revenues:				
Oil sales	$45,685	$40,239	$128,152	$ 90,737
Natural gas sales	23,413	18,036	67,395	44,908
Total operating revenues	69,098	58,275	195,547	135,645
Operating costs and expenses:				
Oil and gas production	8,100	5,524	22,309	14,511
Oil and gas production taxes	5,673	4,621	15,616	10,831
Exploration and abandonments	11,805	3,316	18,110	4,717
Depreciation and depletion	18,003	19,674	55,036	42,170
Accretion of discount on asset retirement obligations	106	87	334	196
Impairments of proved oil and gas properties	1,379	2,679	4,577	5,762
Contract drilling fees stacked rigs			4,269	
General and administrative (including non-cash stock-based compensation of $703 and $1,090 for the three months ended September 30, 2007 and 2006, respectively, and $2,656 and $8,041 for the nine months ended September 30, 2007 and 2006, respectively)	4,646	3,832	16,567	16,044
Ineffective portion of cash flow hedges	(22)	(1,190)	1,134	(64)
(Gain) loss on derivatives not designated as hedges	(3,088)		(3,088)	
Total operating costs and expenses	46,602	38,543	134,864	94,167
Income from operations	22,496	19,732	60,683	41,478
Other income (expense):				
Interest expense	(9,054)	(9,184)	(29,803)	(20,998)
Other, net	484	333	957	907
Total other expense	(8,570)	(8,851)	(28,846)	(20,091)
Income before income taxes	13,926	10,881	31,837	21,387
Income tax expense	(5,972)	(4,351)	(13,335)	(8,664)
Net income	7,954	6,530	18,502	12,723
Preferred stock dividends		(32)	(45)	(1,210)
Effect of induced conversion of preferred stock				11,601
Net income applicable to common shareholders	$ 7,954	$ 6,498	$ 18,457	$ 23,114

Basic earnings per share:				
Net income per share	$ 0.12	$ 0.12	$ 0.30	$ 0.52
Shares used in basic earnings per share	69,067	54,936	60,648	44,710
Diluted earnings per share:				
Net income per share	$ 0.11	$ 0.11	$ 0.29	$ 0.48
Shares used in diluted earnings per share	69,913	58,625	62,858	47,937

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)	6% Series A preferred stock Shares	6% Series A preferred stock Amount	Common stock Shares	Common stock Amount	Additional paid-in capital	Notes receivable from officers and employees	Retained earnings (accumulated deficit)	Accumulated other comprehensive income (loss)	Total stockholders equity
BALANCE AT DECEMBER 31, 2005	12,959	$ 130	8,142	$ 8	$ 135,876	$ (9,012)	$ (6,272)	$ (11,060)	$ 109,670
Comprehensive income									
Net income							19,668		19,668
Deferred hedge gains, net of tax of $4,200								7,736	7,736
Net settlement losses included in earnings, net of tax of $2,030								3,738	3,738
Total comprehensive income									31,142
Issuance of subscribed units	4,518	45	2,259	2	45,329	(3,158)			42,218
Issuance of common stock			578	1	577				578
Conversion of preferred stock	(17,477)	(175)	13,106	13	162				
Issuance of common stock for acquisition			34,795	35	384,301				384,336
Restricted stock issued as stock-based compensation			214		1,044				1,044
Cancellation of restricted stock			(1)						
Stock-based compensation for stock options					7,125				7,125
Stock-based compensation on					975				975

issuance of units							
Accrued interest officer and employee notes				(688)			(688)
6% Series A preferred stock dividends					(1,244)		(1,244)
BALANCE AT DECEMBER 31, 2006	$ 59,093	$ 59	$ 575,389	$ (12,858)	$ 12,152	$ 414	$ 575,156
Comprehensive income							
Net income					18,502		18,502
Deferred hedge losses, net of tax of ($5,977)						(8,323)	(8,323)
Net settlement losses included in earnings, net of tax of $1,022						1,416	1,416
Total comprehensive income							11,595
Restricted stock issued as stock-based compensation	138		1,007				1,007
Stock-based compensation for stock options			1,649				1,649
Issuance of common stock for acquisition obligation	54		650				650
Net proceeds from initial public equity offering	16,466	17	172,985				173,002
Proceeds from officer and employee notes				10,644			10,644
Accrued interest officer and employee notes				(274)			(274)
6% Series A preferred stock dividends					(45)		(45)

BALANCE AT SEPTEMBER 30, 2007	$ 75,751	$ 76	$ 751,680	$ (2,488)	$ 30,609	$ (6,493)	$ 773,384

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

	Nine months ended September 30,	
(in thousands)	**2007**	**2006**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 18,502	$ 12,723
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and depletion	55,036	42,170
Impairments of proved oil and gas properties	4,577	5,762
Accretion of discount on asset retirement obligations	334	196
Exploration expense, including dry holes	17,117	3,204
Non-cash compensation expense	2,656	8,041
Gas imbalances	33	(7)
Ineffective portion of cash flow hedges	1,134	(64)
Deferred rent liability	33	49
Deferred income taxes	11,460	7,603
Interest accrued on officer and employee notes	(274)	(510)
Amortization of deferred loan costs	3,251	1,157
Amortization of discount on long-term debt	480	
(Gain) loss on derivatives not designated as hedges	(3,088)	
Dedesignated cash flow hedges reclassed from AOCI	(722)	
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	11,355	(25,943)
Prepaid insurance and other	135	(1,752)
Accounts payable	(9,230)	2,373
Revenue payable	(5,325)	(289)
Accrued liabilities	1,492	204
Accrued interest	(6,249)	4,024
Income taxes payable	225	
Net cash provided by operating activities	102,932	58,941
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and gas properties	(113,936)	(122,839)
Acquisition of oil and gas properties and other assets	(256)	(413,842)
Additions to other property and equipment	(2,218)	(1,249)
Proceeds from the sale of oil and gas properties	96	
Post-dedesignation settlements on dedesignated cash flow hedges	1,286	
Net cash used in investing activities	(115,028)	(537,930)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt	283,600	563,005
Payments of long-term debt	(433,700)	(150,000)

Proceeds from issuance of subscribed units and common stock	173,002	61,178
Payments of preferred stock dividends	(132)	(2,542)
Proceeds from repayment of officer and employee notes	10,644	
Payments for loan origination costs	(2,572)	(5,500)
Negative cash balances		3,666
Net cash provided by financing activities	30,842	469,807
Net increase (decrease) in cash and cash equivalents	18,746	(9,182)
BEGINNING CASH AND CASH EQUIVALENTS	1,122	9,182
ENDING CASH AND CASH EQUIVALENTS	$ 19,868	$
SUPPLEMENTAL CASH FLOWS:		
Cash paid for interest and fees, net of $2,160 and $1,415 capitalized	$ 28,233	$ 11,294
Cash paid for income taxes	$ 2,050	$ 100
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Issuance of common stock in acquisition of oil and gas properties and other assets	$ 650	$ 384,336
Deferred tax effect of acquired oil and gas properties	$	$ 227,537
Issuance of notes receivable in connection with capital options	$	$ 3,158
Discount on long-term debt	$ (1,000)	$

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

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 from the Chase Group 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 individuals 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 hereafter collectively referred to 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 their ownership in certain oil and gas properties in Southeast New Mexico to Resources in exchange for cash in the aggregate amount of approximately $409 million and 34,794,638 shares of Resources common stock. As of September 30, 2007 and December 31, 2006, this ownership of the Chase Group represented approximately 37 percent and 59 percent, respectively, of the total outstanding common stock ownership 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 and certain shareholders, including our 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*.

Reverse stock split. A one-for-two reverse stock split of the Company s outstanding common stock, which was approved by the Company s shareholders, became effective upon the completion of the Company s initial public offering. All common shares and per share amounts in the accompanying consolidated financial statements and notes to the consolidated financial statements have been retroactively adjusted for all periods presented to give effect to the reverse stock split.

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

Principles of consolidation. Prior to the Combination, the consolidated financial statements of Resources represent the accounts of CEHC and its wholly owned subsidiaries. After the Combination, 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, 2006 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 September 30, 2007, its income for the three and nine months ended September 30, 2007 and 2006 and its cash flows for the nine months ended September 30, 2007 and 2006. All such adjustments are of

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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 Registration Statement on Form S-1, as amended (Registration No 333-142315).

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 September 30, 2007, 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 $610,000 related to the Company s overtake position of 94,601 Mcf on certain wells and a gas imbalance receivable, included in *Other assets* in the accompanying consolidated balance sheet of approximately $337,000 related to the Company s undertake position of 74,985Mcf on certain wells.

General and administrative expense. The Company receives fees for the operation of jointly owned oil and gas properties and records such reimbursements as reductions of General and administrative expense. Such fees totaled approximately $222,000 and $181,000 for the three months ended September 30, 2007 and 2006, respectively, and totaled approximately $852,000 and $602,000 for the nine months ended September 30, 2007 and 2006, 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 September 30, 2007 and December 31, 2006 of capitalized exploratory well costs based on the date the drilling was completed:

(in thousands)	**September 30, 2007**	**December 31, 2006**
Wells in progress	$ 3,104	$ 916
Capitalized exploratory well costs that have been capitalized for a period of one year or less	15,398	14,042
Capitalized exploratory well costs that have been capitalized for a period greater than one year	3,329	4,915
Total exploratory well costs	$21,831	$ 19,873

During 2006 and 2007, the Company drilled four vertical exploration wells in the Western Delaware Basin of Texas. One of the four wells is currently flowing gas to sales. Below is a description of the status of the remaining three wells.

As of June 30, 2007, the first well drilled had been completed in two of the four prospective formations that are being tested in the project area and had found both zones capable of producing gas in the vertical well bores; however, quantities found were not commercial. The evaluation conducted on this well in the third quarter was to determine the viability of another one of the four prospective formations which is deeper than the formations to which the well had previously been completed. This formation is a shale formation which is present and productive in another of the Company s exploratory wells located in the Western Delaware

Basin. The evaluation of this formation indicated that conditions were unfavorable for commercial success. This well was temporarily abandoned, and the Company expensed the costs associated with this well in the third quarter of 2007, which were approximately $6.8 million. Such expense is included in *Exploration and abandonments* in the accompanying consolidated statement of operations for the three and nine months ended September 30, 2007.

The second well drilled in the project area, which reached total depth in September 2006, was completed and flowing gas to sales during its initial evaluation stage during the six months ended June 30, 2007; however, quantities found were not commercial. The Company has begun testing a deeper formation in this well bore. The Company is still evaluating the commercial viability of the deeper zone. As such, the Company recognized exploratory dry hole expense of approximately $1.8 million which represents the intangible drilling and completion costs incurred to drill to the shallower formations which were not commercial. Such expense is included in *Exploration and abandonments* in the accompanying consolidated statement of operations for the three months and nine months ended September 30, 2007. Remaining accumulated capitalized exploratory costs on this well of approximately $3.3 million related to the drilling of the deeper formation currently being evaluated are included above in Capitalized exploratory well costs that have been capitalized for a period greater than one year.

During 2007, a third well in the Western Delaware Basin was drilled to a shallower, previously untested, prospective formation. During June 2007, the Company determined that the well had not found sufficient reserves to justify its completion or its inclusion in the evaluation of the viability of any additional prospective formations in the project area. The well was temporarily abandoned, and the Company has recognized exploratory dry hole expense of approximately $3.0 million. Such expense is included in *Exploration and abandonments* in the accompanying consolidated statement of operations for the nine months ended September 30, 2007.

The remaining capitalized exploratory wells in progress and exploratory well costs of approximately $18.5 million have been deferred for a period of one year or less and are related primarily to the Company s New Mexico Shelf and New Mexico Basin properties.

The changes in capitalized exploratory well costs were as follows:

	Nine months ended September 30,	
(in thousands)	**2007**	**2006**
Beginning capitalized exploratory well costs	$ 19,873	$ 3,955
Additions to exploratory well costs pending the determination of proved reserves	64,712	31,387
Reclassifications due to determination of proved reserves	(57,839)	(18,849)
Exploratory well costs charged to expense	(4,915)	
Ending capitalized exploratory well costs	$ 21,831	$ 16,493

The Company charged $16,222,000 and $3,172,000 of exploratory well costs to expense during the nine months ended September 30, 2007 and 2006, respectively. These exploratory well costs were capitalized and subsequently expensed in the same annual period; therefore, they are not included in the table above in accordance with FSP No. 19-1.

Note D. *Business combination*

On February 27, 2006, the Company closed a Combination Agreement with the Chase Group whereby ownership in certain oil and gas properties and non-producing leasehold acreage in Southeast New Mexico (the Chase Group Properties) were combined with the properties previously owned by CEHC. The results of the Chase Group Properties have been included in the consolidated financial statements since that date.

As discussed in Note K *Commitments and contingencies*, the Company was obligated under the Combination Agreement to offer to purchase additional working interests in the Chase Group Properties from nine individuals within the Chase Group for total consideration of approximately $906,000. In April 2007, the Company satisfied this obligation by paying $256,000 in cash and issuing 54,230 shares of common stock. This aggregate purchase price is reflected in *Proved properties* and the related obligation is reflected in *Chase Group unaccredited investors asset purchase obligation* in the accompanying consolidated balance sheet as of December 31, 2006.

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The following table represents pro forma consolidated statements of operations as though the Combination had been completed as of January 1, 2006:

(in thousands, except per share data)

Pro forma nine months ended September 30, 2006 (unaudited)	
Operating revenues	$157,101
Net income applicable to common shareholders	$ 16,951
Earnings per common share:	
Basic	$ 0.31
Diluted	$ 0.30

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. This agreement was terminated and replaced with a Transition Services Agreement on April 23, 2007, which terminated upon completion of the Company s initial public offering on August 7, 2007. See further discussion in Note M *Related parties*.

Note E. *New accounting pronouncements*

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company will adopt SFAS No. 157 effective January 1, 2008. The Company is currently evaluating the impact of SFAS No. 157.

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. The Company will adopt this statement January 1, 2008, and the Company does not expect that it will elect the fair value option for any of its eligible financial instruments and other items.

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, the Company does not intend to adopt EITF Issue 06-11 prior to the required effective date of January 1, 2008. The Company does not expect the adoption of EITF Issue 06-11 to have a significant effect on its financial statements since the Company historically has accounted for the income tax benefits of dividends paid for share-based payment awards in the manner described in the consensus.

The FASB issued FSP FIN No. 48-1, Definition of *Settlement* in FASB Interpretation No. 48, to clarify when a tax position is effectively settled. This guidance is important 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. The FSP 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 does not expect the adoption of this pronouncement to have a significant effect on its financial statements.

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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.

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

(in thousands)

Nine months ended September 30, 2007	
Asset retirement obligations at beginning of period	$ 8,700
Liability incurred upon acquiring and drilling wells	309
Accretion expense	334
Liabilities settled upon plugging, abandoning or selling wells	(34)
Revisions to estimated cash flows	(2,032)
Asset retirement obligations at end of period	$ 7,277

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. Preferred stock dividends of approximately $32,000 were paid during the three months ended September 30, 2006. There were no dividend payments made during the three months ended September 30, 2007. Preferred stock dividends of approximately $132,000 and $2,542,000 were paid during the nine months ended September 30, 2007 and 2006, 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 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.

At September 30, 2007, the Company had Purchase Notes receivable from certain employees of approximately $2,488,000 comprised of an aggregate principal amounts of $2,214,000 and accrued interest of $274,000.

Stock issuances treated as Capital Options. The following table summarizes the Bundled Capital Options activity for the nine months ended September 30, 2007:

	Number of Bundled Capital Options	Weighted average exercise price
Nine months ended September 30, 2007		
Outstanding at beginning of period	938,303	$ 9.52
Bundled Capital Options exercised	(938,303)	$ 9.52
Outstanding at end of period		$
Vested outstanding at end of period		$

The following table summarizes the Capital Options activity for the nine months ended September 30, 2007:

	Number of Capital Options	Weighted average exercise price
Nine months ended September 30, 2007		
Outstanding at beginning of period	425,221	$ 9.81
$10 Capital Options exercised	(179,557)	$ 9.30
$15 Capital Options exercised	(8,530)	$ 12.13
Outstanding at end of period	237,134	$ 10.12
Vested outstanding at end of period	237,134	$ 10.12

The following table summarizes information about the Company s vested Capital Options outstanding and exercisable at September 30, 2007:

	Capital Options outstanding,	Weighted average remaining	Weighted average

		vested and exercisable	contractual life	exercise price	Intrinsic value
Vested Capital Options Outstanding and Exercisable					
Exercise price	$ 10.00	129,656	2.79 years	$ 8.33	$ 970,000
Exercise price	$ 15.00	107,478	3.07 years	$ 12.27	237,000
		237,134		$ 10.12	$ 1,207,000

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The following table summarizes the stock-based compensation for all Capital Options and is included in *General and administrative expense* in the accompanying consolidated statement of operations for the three and nine months ended September 30, 2007 and 2006:

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
Stock-based compensation expense from Capital Options:	$	$	$	$ 975,000
Bundled Capital Options				
Stock-based compensation expense	$	$	$	$ 508,000
Options vesting during period				242,000
Weighted average grant date fair value per option	$	$	$	$ 2.10
Capital Options				
Stock-based compensation expense	$	$	$	$ 467,000
Options vesting during period				119,799
Weighted average grant date fair value per option	$	$	$	$ 3.90

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* and Note D *Business combination*, 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 Note D *Business combination* 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.

Common stock held in escrow. On February 27, 2006 the Company entered into an agreement with certain stockholders of the Company in which certain of the Company s shareholders placed 430,755 shares of Resources common stock in an escrow account (the Escrow Agreement). The Escrow Agreement provided that if, on or before February 27, 2007 (the Initial Period), the Company consummated one of two specified transactions, the shares held in escrow would be released to the Company for reissuance to Messrs. Leach, Beal, Copeland, Kamradt and Wright. Neither of those specified transactions occurred in the Initial Period. However, the Escrow Agreement specified that if neither of the two specified transactions occurred during the Initial Period, a sale of the Company in a business combination on or before August 26, 2007 where the per share valuation of the Company s common stock in such sale was equal to or greater than $28.00 per share would result in the release of the shares held in escrow to the Company for reissuance to Messrs. Leach, Beal, Copeland, Kamradt and Wright. These shares have been treated as issued and outstanding in the consolidated financial statements at September 30, 2007 and December 31, 2006. This conditions for release of these shares to Messrs. Leach, Beal, Copeland, Kamradt and Wright were not met by August 26, 2007.

As a result, the escrow agent has been instructed to distribute the escrowed shares to the original owners of the shares.

Note H. ***Stock incentive plan***

The Company s 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.

Restricted stock awards. Under the Plan, the Company has issued 349,756 restricted shares, of which restrictions have lapsed with respect to 60,000 shares.

On April 23, 2007, the Company issued a total of 20,000 shares of restricted common stock comprised of 2,500 shares to each of the eight outside directors subject to certain restrictions as set forth in the Plan. These restrictions lapsed with respect to 100 percent of

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the restricted shares on April 23, 2007, the date of grant. The grant date fair value of the stock was estimated to be approximately $340,000 which the Company recognized as stock-based compensation expense in April 2007.

In August 2007, the Company s board of directors appointed a new director who was granted 5,000 shares of restricted common stock by the Compensation Committee of the Company s board of directors in accordance with the Company s director compensation plan, subject to certain restrictions as set forth in the Plan and a restricted stock agreement between the Company and such director. These restrictions lapse with respect to 100 percent of the restricted shares twelve months from the date of grant. The grant date fair value of the stock was estimated by the Company to be approximately $64,000, which the Company will recognize as stock-based compensation expense over twelve months beginning August 2007.

In September 2007, the Compensation Committee of the Company s board of directors approved the grant of 112,540 shares of restricted common stock to the non-officer employees of the Company, subject to certain restrictions as set forth in the Plan and respective restricted stock agreements between the Company and each such employee. These restrictions lapse with respect to 100 percent of the restricted shares three years from the date of grant. The grant date fair value of the stock was estimated by the Company to be approximately $1,629,000 which the Company will recognize as stock-based compensation expense over the next three years beginning September 2007.

All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If an employee terminates employment prior the lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company s restricted stock awards during the nine months ended September 30, 2007 is presented below:

	Number of common shares	**Grant date fair value**
Nine months ended September 30, 2007		
Outstanding at beginning of period	212,216	
Shares granted	137,540	$2,033,000
Shares cancelled / forteited		
Lapse of restrictions	(60,000)	
Outstanding at end of period	289,756	

The Company recorded stock-based compensation for restricted stock of $226,000 and $472,000, which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations, for the three months ended September 30, 2007 and 2006, respectively, and $1,007,000 and $560,000 for the nine months ended September 30, 2007 and 2006, respectively. Future stock-based compensation expense related to restricted stock outstanding at September 30, 2007 for the remaining three months of 2007 and the years ending December 31, 2008, 2009 and 2010 is expected to be approximately $370,000, $1,420,000, $992,000 and $403,000, respectively. The income tax benefit recognized in the accompanying statement of operations for restricted stock was approximately $95,000 and $184,000 for the three months ended September 30, 2007 and 2006, respectively, and $422,000 and $218,000 for the nine months ended September 30, 2007 and 2006, respectively.

Stock option awards. On August 15, 2007, the Company s board of directors approved the issuance of 200,000 stock options to a newly appointed officer of the Company and 15,000 stock options to a non-officer employee of the Company under the Plan. These options have an exercise price of $12.85, a contractual term of 10 years from the date of grant, and vest using a four year graded vesting schedule.

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In calculating the compensation expense for these options, the Company has estimated the fair value of each grant using the Black-Scholes option-pricing model. Assumptions utilized in the model are shown below.

Risk-free interest rate	4.47%
Expected term (years)	6.25
Expected volatility	37.33%
Expected dividend yield	0.00%

A summary of the Company s stock option activity under the Plan for the nine months ended September 30, 2007 is presented below:

	Number of options[a]	**Weighted Average Price**
Nine months ended September 30, 2007		
Outstanding at beginning of period	2,797,997	$ 8.93
Options granted	215,000	$12.85
Options forfeited	(1,275)	$ 8.00
Options exercised		$
Outstanding at end of period	3,011,722	$ 9.21
Exercisable at end of period	2,063,499	$ 8.60

The following table summarizes information about the Company s vested stock options exercisable at September 30, 2007:

		Number vested and exercisable	**Weighted average remaining contractual life**	**Weighted average exercise price**	**Intrinsic value**
Vested Options Exercisable					
Exercise price	$ 8.00	1,753,819	7.72 years	$ 8.00	$ 11,944,000
Exercise price	$ 12.00	309,680	8.33 years	$ 12.00	870,000
		2,063,499		$ 8.60	$ 12,814,000

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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 nine months ended September 30, 2007 and 2006:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
Grant date fair value:				
Time Vesting options [a]	$ 87,000	$	$ 87,000	$1,931,000
Performance Vesting options:				
Officers [b]				500,000
Certain employee [b]				31,000
Non-officers [c]				142,000
Current officer stock options [d]	1,156,000		1,156,000	3,555,000
Total	$1,243,000	$	$1,243,000	$6,159,000
Stock-based compensation expense from stock options:				
Time Vesting options [a]	$ 6,000	$	$ 6,000	$5,085,000
Performance Vesting options:				
Officers [b]	141,000	141,000	$ 420,000	335,000
Certain employee [b]	10,000	10,000	$ 30,000	24,000
Non-officers [c]			$	505,000
Current officer stock options [d]	319,000	467,000	$1,193,000	558,000
Total	$ 476,000	$618,000	$1,649,000	$6,507,000

(a) Options granted prior to February 27, 2006, vested immediately as of the date of the Combination, as a result of a change of control. Options granted thereafter vest using a four year graded vesting schedule by approval from the Board of Directors.

(b) Options granted prior to February 27, 2006, vest using a three year cliff vesting schedule by approval from CEHC s Board of Directors.

(c) Vested as of the date of the Combination by approval from CEHC s Board of Directors.

(d) Vest using a four year graded vesting schedule by approval from the Board of Directors.

Future stock-based compensation expense related to incentive stock options outstanding at September 30, 2007 for the remaining three months ended December 31, 2007 and the years ending December 31, 2008, 2009, 2010 and 2011 is expected to be approximately $558,000, $1,853,000, $720,000, $240,000 and $48,000, respectively.

Income tax benefit recognized in the income statement for these stock-based compensation arrangements was $200,000 and $241,000 for the three months ended September 30, 2007 and 2006, respectively, and $691,000 and $2,538,000 for the nine months ended September 30, 2007 and 2006, respectively. No amounts have been treated as deductions to the Company s current taxable income for the three or nine months ended September 30, 2007 and 2006, since no options have been exercised.

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 2006, 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. 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, Accounting for Derivative Instruments and Hedging Activities, as amended (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. In prior quarters, prices received for the Company s natural gas have been 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 prospectively hedge accounting 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, is considered the last date the Company s natural gas hedges were highly effective, and the Company must discontinue hedge accounting during the three months ended September 30, 2007 and all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges will be 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, will remain in *AOCI* and be reclassified into earnings under *Natural gas revenues*, during the periods which the hedged forecasted transaction affects earnings.

Derivatives not designated as cash flow hedges. On September 20, 2007, the Company entered into four crude oil price swaps to hedge an additional portion of its estimated crude oil production for calendar years 2008 and 2009. The contracts are for 1,000 Bbls per day each with various fixed prices. 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.*

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The following table sets forth the Company s outstanding crude oil and natural gas zero cost price collars and price swaps at September 30, 2007:

	Fair Market Value Asset / (Liability) (in thousands)	Aggregate remaining volume	Daily volume	Index price	Contract period
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price collar	$ (2,278)	59,800	650	$ 37.95 - $41.75(a)	10/1/07 - 12/31/07
Price swap	(2,570)	211,600	2,300	$ 67.85(a)	10/1/07 - 12/31/07
Price swap	(7,668)	951,600	2,600	$ 67.50(a)	1/1/08 - 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	735	1,472,000	16,000	$ 5.98 - $9.75(b)(c)	10/1/07 - 12/31/07
Price collar	1,740	4,941,000	13,500	$ 6.50 - $9.35(b)	1/1/08 - 12/31/08
Price swap	257	193,200	2,100	$ 7.40(b)	10/1/07 - 12/31/07
Derivatives not designated as cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	(33)	732,000	2,000	$ 75.78(a)(c)	1/1/08 - 12/31/08
Price swap	71	730,000	2,000	$ 72.84(a)(c)	1/1/09 - 12/31/09
Net liability	$ (9,746)				

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

(b) The index prices for the natural gas price collars and price swaps are based on the Inside FERC-El Paso Permian Basin first-of-the-month spot price.

(c) Amounts disclosed represent weighted average prices.

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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:*

	Nine months ended September 30,	
(in thousands)	**2007**	**2006**
Effect of derivatives included in oil and gas revenue:		
Cash payments on cash flow hedges in oil sales	$ (3,347)	$ (7,456)
Cash receipts from cash flow hedges in gas sales	187	114
Dedesignated cash flow hedges reclassed from AOCI	722	
Total oil and gas revenue from derivatives	$ (2,438)	$ (7,342)
Gain (loss) on derivatives not designated as cash flow hedges:		
Mark-to-market	$ 1,802	$
Cash receipts on dedesignated derivatives	1,286	
Total gain (loss) on derivatives not designated as cash flow hedges	$ 3,088	$
Ineffective portion of cash flow hedges	$ (1,134)	$ 64
Accumulated other comprehensive income (loss):		
Cash flow hedges:		
Mark-to-market of cash flow hedges gain (loss)	$(14,300)	$ 5,552
Reclassification adjustment for (gains) losses included in net income	3,160	7,342
Net AOCI upon dedesignation at June 30, 2007	(407)	
Net change, before taxes	(11,547)	12,894
Tax effect	4,822	(4,518)
Net change, net of tax	$ (6,725)	$ 8,376
Dedesignated cash flow hedges:		
Net AOCI upon dedesignation at June 30, 2007	$ 407	$
Reclassification adjustment for (gains) losses included in net income	(722)	
Total net change in AOCI (loss), net of tax	(315)	
Tax effect	133	

Net change, net of tax	$	(182)	$

All of the Company s derivatives are expected to settle by January 8, 2010. Based on futures prices as of December 31, 2006, the Company expected a pre-tax loss of $211,000 to be reclassified into earnings during the year ended December 31, 2007. Based on futures prices as of September 30, 2007, the Company expects a pre-tax loss of $9,644,000 and pre-tax gain of $121,000 to be reclassified out of *AOCI* into earnings during the twelve months ended September 30, 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 consists of the following:

(in thousands)	September 30, 2007	December 31, 2006
Bank debt:		
1st Lien Credit Facility	$234,000	$455,700
2nd Lien Credit Facility		39,400
New 2nd Lien Credit Facility	110,400	
Unamortized original issue discount on New 2nd Lien Credit Facility	(520)	
Total long-term debt	$343,880	$495,100
Current portion of New 2nd Lien Credit Facility	2,000	400
Total debt	$345,880	$495,500

Refinancing of debt facilities. As of March 27, 2007, the Company amended its revolving credit facility with a syndicate of banks (the 1st Lien Credit Facility), repaid its term loan facility (the 2nd Lien Credit Facility) and entered into a new 2nd lien credit facility (the New 2nd Lien Credit Facility).

The amendment to the 1st Lien Credit Facility allows for the incurrence of additional indebtedness in the form of a $200 million second lien term loan. The amendment also redetermined the borrowing base at $375 million and increased the maximum allowable 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 from 3.5 to 1.0 to 4.0 to 1.0. The amount outstanding under this facility at September 30, 2007 was $234.0 million, all of which was at the Eurodollar rate.

On March 27, 2007, the Company entered into 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 2nd 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 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 (7.75 percent at September 30, 2007) 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 the sooner to occur of an initial public offering by the Company or the first anniversary of the closing date of the loan; thereafter, interest margins on Eurodollar rate advances and prime rate advances will be 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 beginning 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. The Company will not incur a prepayment penalty on any principal amount prepaid during the first twelve months of the loan. 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. After the third year, 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 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 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 and (c) restrictions as to merger and sale or transfer of assets.

The amount outstanding under New 2nd Lien Credit Facility at September 30, 2007 was $111.9 million, net of a discount of $0.5 million, all of which was at the Eurodollar rate. The Company was in compliance with all covenants of the New 2nd Lien Credit Facility at September 30, 2007.

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

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 2nd Lien Credit Facility repaid in full on March 27, 2007, were written off and included in *Interest expense* in the first quarter of 2007.

Repayment of portion of New 2nd Lien Credit Facility. As mentioned 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 $112.9 million. As set forth by this facility s credit agreement, effective on the consummation of the IPO on August 9, 2007, the interest margins on Eurodollar rate advances and prime rate advances increased to 425 basis points and 275 basis points, respectively.

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 at September 30, 2007 for the three months ended December 31, 2007 and the years ended December 31, 2008, 2009, 2010 and 2011 and thereafter, are as follows:

(in thousands)

2007	$ 500
2008	2,000
2009	2,000
2010	236,000
2011	2,000
2012 and thereafter	103,900
Total	$ 346,400

Note K. *Commitments and contingencies*

Daywork drilling contract commitments. The Company signed a daywork drilling contract with a drilling contractor (Contractor B) 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 no contract drilling fees related to stacked rigs in the three months ended September 30, 2007 and approximately $1,296,000 during the nine months ended September 30, 2007, respectively. These costs were minimized as Contractor B 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 Contractor B on June 26, 2007, that provides the Company exclusive use of one rig for a term that commenced on July 3, 2007 and ends 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 Contractor B is liable for its employees, subcontractors and invitees. In addition, Contractor B is responsible for pollution or contamination from their equipment. Contractor B will release the Company of any liability for negligence of any party in connection with Contractor B. The operating day rate is $14,000. The operating day rate can be revised to reflect changes in costs incurred by Contractor B 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 Contractor B secures work for the subject rig with a new customer prior to the end of the contract term, Contractor B 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.

The Company signed daywork drilling contracts with Silver Oak Drilling, LLC (Silver Oak), an affiliate of the Chase Group, on August 1, 2006, that provides the Company use of four drilling rigs for a term that commenced on August 1, 2006 and ended on July 31, 2007. The Company may direct the rig to locations located in New Mexico as needed. If the Company moves 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 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 contract for the remainder of the term to the extent the rig has 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 no contract drilling fees related to stacked rigs in the three months ended September 30, 2007 and approximately $2,973,000 during the nine months ended September 30, 2007, based on the drilling agreement 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 is in effect until drilling operations are completed on specified wells or for a term of 1 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 contract for the remainder of the term to the extent the rig has not been committed to a third party in mitigation of the Company s damages.

Oil & gas lease extension payment. The Company is party to an agreement which, in part, governs the exploration activities on the Company s acreage in the Western Delaware Basin shale play in Culberson County, Texas. The agreement contains a three-well drilling commitment. In addition to the drilling well requirement, the agreement required the Company to pay an additional $2.1 million ($150 per net acre for 13,952 net acres) in order to maintain its leasehold position, with such payment required within 90 days after the completion of the drilling of the third of the Company s three-well drilling commitment.

As of January 1, 2007, the Company had drilled or was drilling all three of these wells. The last of the three wells drilled reached total depth on January 19, 2007. On April 17, 2007, the Company made the payment of $2.1 million described above.

Chase Group accredited and unaccredited investors asset purchase obligation. As discussed in Note D *Business combination*, on February 27, 2006, as required by the Combination Agreement, the Company agreed to purchase working interests in the Chase Group Properties from certain individuals within the Chase Group. On May 18, 2006, the Company purchased interests in the Chase Group Properties from ten individuals within the Chase Group who were accredited investors in exchange for $8.9 million in cash and 111,323 shares of Resources common stock valued at $1.4 million for an aggregate purchase price of $10.3 million. The value of the common shares issued was $12 per share, as required by the Combination Agreement. The aggregate purchase price is reflected in *Proved properties* in the accompanying consolidated balance sheet at December 31, 2006. This transaction is included in the aggregate purchase price disclosed in Note D *Business combination*.

The Company was further obligated to offer to purchase additional interests in the Chase Group Properties from nine individuals within the Chase Group. In April 2007, the Company satisfied this obligation by paying $256,000 in cash and issuing 54,230 shares of common stock. The aggregate purchase price is reflected in *Proved properties* and the related obligation is reflected in *Chase Group*

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unaccredited investors asset purchase obligation in the accompanying consolidated balance sheet at December 31, 2006. This transaction is included in the aggregate purchase price disclosed in Note D *Business combination*.

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 48) an interpretation of FASB Statement No. 109 Accounting for Income Taxes , on January 1, 2007. At the time of adoption and as of September 30, 2007, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2004 2006 remain subject to examination by major tax jurisdictions.

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. The effective income tax rate for the nine months ended September 30, 2007 was 41.9%.

Note M. ***Related parties***

Contract operator agreement. On February 27, 2006, the Company signed a contract operator agreement with 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 provided certain field level operating services on the Chase Group Properties.

Transition Services Agreement. On April 23, 2007, the Company entered into a Transition Services Agreement with MEC whereby it provided services to the properties in Southeast New Mexico that the Company acquired from Chase Oil and its affiliates in the Combination. The Transition Services Agreement replaced the prior contract operator agreement with MEC. 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. The Transition Services Agreement terminates upon the earlier to occur of (i) February 28, 2011; (ii) the date on which the Company completes the initial sale of its shares of common stock to the public pursuant to a registration statement filed under the Securities Act of 1933, as amended; or (iii) a change of control, as defined, or sooner as otherwise provided in the agreement or mutually agreed upon by the parties. The Transition Services Agreement was terminated effective August 7, 2007 upon the Company s completion of its initial public offering. Accordingly, 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 $1.7 and $11.9 million for the three and nine months ended September 30, 2007, respectively, for services rendered under the contract operator agreement and Transition Services Agreement.

The Company incurred charges from MEC of approximately $5.5 million for both the three and nine months ended September 30, 2006 for services rendered under the contract operator agreement.

At September 30, 2007, the Company had outstanding invoices payable to MEC of approximately $0.7 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

At December 31, 2006, the Company had outstanding invoices payable to MEC of approximately $1.8 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 $13.5 million and $35.6 million for the three and nine months ended September 30, 2007, respectively, for services rendered.

The Company incurred charges from these related party vendors of approximately $15.9 million and $29.3 million for the three and nine months ended September 30, 2006, respectively, for services rendered.

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At September 30, 2007, the Company had outstanding invoices payable to the other related party vendors identified above of approximately $2.2 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheets.

At December 31, 2006, the Company had outstanding invoices payable to the other related party vendors mentioned above of approximately $1.8 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

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 $672,000 and $1,645,000 for the three and nine months ended September 30, 2007, respectively. The amount paid attributable to such interests was approximately $29,000 and $1,002,000 for the three and nine months ended September 30, 2006.

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 approximately $50,000 and $109,000 for the three and nine months ended September 30, 2007, respectively, and approximately $15,000 and $16, 000 for the three and nine months ended September 30, 2006. The Company also paid this entity a $24,000 lease bonus during the nine months ended September 30, 2007. The Company had no outstanding invoices payable to this entity as of September 30, 2007 or December 31, 2006.

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 is now owned equally by such officer and a non-officer employee of the Company. The amount attributable to such interest was approximately $1,000 and $3,000 during the three and nine months ended September 30, 2007. During the three and nine months ended September 30, 2006, no payments were made related to this overriding royalty interest.

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.

The Company paid Caza approximately $43,000 and $1,798,000 for the three and nine months ended September 30, 2006 for these interests. Approximately all of the costs were capital prospect costs which are reflected in *Unproved properties* in the accompanying consolidated balance sheet at December 31, 2006.

The Company paid Caza approximately $3,000 for the nine months ended September 30, 2007 for delay rentals which are reflected in *Unproved properties* in the accompanying consolidated balance sheet at September 30, 2007. There were no amounts paid to Caza during the three months ended September 30, 2007 for these interests.

At September 30, 2007 and December 31, 2006, the Company had no outstanding invoices owed to Caza.

Note N. *Net income per share*

Basic 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.

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 (as issued under the Stock Option Plan of CEHC adopted in 2004 and the Plan of CRI adopted in 2006, both as described in Note H *Stock incentive plan*) and restricted stock. Potentially dilutive effects are calculated using the treasury stock method.

The CEHC 6% Series A Preferred Stock were entitled to receive an amount equal to its stated value ($9.00) plus any unpaid dividends upon occurrence of a liquidation event, as defined. In connection with the Combination on February 24, 2006, a liquidation event occurred. Instead of receiving the stated value, the holders of the CEHC 6% Series A Preferred Stock agreed to accept

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0.75 shares of Resources common stock in exchange for each share of CEHC 6% Series A Preferred Stock. This was considered to be an induced conversion, as defined in the FASB Emerging Issues Task Force Topic D-42, The Effect on the Calculation of Earnings per Share for the Redemption or Induced Conversion of Preferred Stock. The excess of the carrying amount of the CEHC 6% Series A Preferred Stock over the fair value of the Resources common stock issued is required to be added to 2006 net income to arrive at 2006 net income applicable to common shareholders for the nine months ended September 30, 2006.

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 nine months ended September 30, 2007 and 2006:

	Three months ended September 30,		**Nine months ended September 30,**	
(in thousands)	**2007**	**2006**	**2007**	**2006**
Weighted average common shares outstanding				
Basic	69,067	54,936	60,648	44,710
Dilutive Bundled Capital Options		2,665	1,130	2,443
Dilutive Capital Options	83	221	163	174
Dilutive common stock options	710	779	852	602
Dilutive restrictive stock	53	24	65	8
Diluted	69,913	58,625	62,858	47,937

Since the Company had net income applicable to common shareholders, the effects of all potentially dilutive securities including Bundled Capital Options, Capital Options, incentive stock options and unvested restricted stock were considered in the computation of diluted earnings per share. Because the exercise prices of certain incentive stock options were greater than the average market price of the common shares and would be anti-dilutive, incentive stock options to purchase 665,000 shares of common stock for the three and nine months ended September 30, 2007 and incentive stock options to purchase 450,000 shares of common stock for the three and nine months ended September 30, 2006 were outstanding but not included in the computations of diluted income per share from continuing operations.

Note O. ***Supplementary information***

Costs incurred for oil and gas producing activities

	Three months ended September 30,		**Nine months ended September 30,**	
(in thousands)	**2007**	**2006**	**2007**	**2006**
Property acquisition costs:				
Proved	$ 3,801	$ (1,140)	$ 11,801	$ 822,810
Unproved	1,857	3,483	(2,239)	218,848
Exploration	29,239	13,266	70,973	27,912
Development	26,880	34,647	44,253	85,235
Capitalized asset retirement obligations	(662)	(129)	(1,951)	6,274
Total costs incurred for oil and gas properties	$61,115	$50,127	$122,837	$1,161,079

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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 management s discussion and analysis contained in our Prospectus dated August 2, 2007 and filed with the Securities and Exchange Commission (SEC) pursuant to Rule 424 (b) on August 3, 2007, as well as with the consolidated financial statements and notes thereto included in this quarterly report on Form 10-Q.

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 oil and natural gas properties. Our conventional operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. These conventional operations are complemented by our activities in unconventional emerging resource plays. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on our multi-year project inventory and through acquisitions that meet our strategic and financial objectives.

Our operations are primarily concentrated in the Permian Basin, the largest onshore oil and gas basin in the United States. As of December 31, 2006, 99% of our total estimated net proved reserves were located in the Permian Basin and consisted of approximately 57% crude oil and 43% natural gas. This basin is characterized by an extensive production history, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators. The primary producing formation in the Permian Basin under our core properties in Southeast New Mexico is the Yeso formation, including the Paddock interval, which is located at depths ranging from 3,800 feet to 5,800 feet, and the Blinebry interval, the top of which is located approximately 400 feet below the base of the Paddock interval. We have assembled a multi-year inventory of development drilling and exploitation projects, including further projects targeting the Yeso formation, that we believe will allow us to grow proved reserves and production. We have also acquired significant acreage positions in unconventional emerging resource plays, where we intend to apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies.

Factors that significantly affect our results

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices have historically been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas that we can economically produce and our ability to access capital.

We generally hedge a portion of our expected future oil and natural gas production to reduce our exposure to fluctuations in commodity price. See Liquidity and capital resources Hedging for a discussion of our hedging and hedge positions.

Like all businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well decreases. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce and by implementing secondary recovery techniques. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production. We will maintain our focus on costs necessary to produce our reserves as well as the costs necessary to add reserves through drilling and acquisitions. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost-effective manner and to timely obtain drilling permits and regulatory approvals.

Items impacting comparability of our financial results

Our historical results of operations for the periods presented may not be comparable, either from period to period or going forward, for the reasons described below.

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Combination transaction

We were formed in February 2006 as a result of the combination transaction between Concho Equity Holdings Corp. and Chase Oil Corporation, Caza Energy LLC (Caza) and certain other parties thereto (collectively with Chase Oil Corporation and Caza, the Chase Group).

Concho Equity Holdings Corp. is our predecessor for accounting purposes. As a result, our historical financial statements prior to February 27, 2006, are the financial statements of Concho Equity Holdings Corp. Concho Equity Holdings Corp. was formed on April 21, 2004, and did not own any material assets and did not conduct substantial operations other than organizational activities until it acquired oil and gas properties from Lowe Partners, LP on December 7, 2004 (the Lowe Acquisition). For a discussion of the results of operations of Concho Resources Inc. (Resources) (as the accounting successor to Concho Equity Holdings Corp.), please read Results of operations of Concho Resources Inc.

As of December 31, 2006, approximately 76% of our PV-10 was attributable to the properties contributed to us by the Chase Group in the combination transaction.

Additional indebtedness and other expenses

During 2006 and 2007, we incurred additional indebtedness and other expenses as a result of our rapid growth, particularly as a result of the combination transaction. Our historical financial information prior to February 28, 2006 does not give effect to the results of operation of the properties contributed by the Chase Group in the combination transaction, as well as, the following items:

§ we closed the combination transaction on February 27, 2006;

§ we incurred approximately $405 million of new indebtedness upon the initial closing of the combination transaction;

§ we entered into a $200.0 million second lien term loan facility (the New 2nd Lien Credit Facility) on March 27, 2007, from which we received proceeds of $199.0 million to repay the $39.8 million outstanding under our prior term loan facility, to reduce the outstanding balance under our revolving credit facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes; and

§ we have incurred additional general and administrative costs as a result of the expansion of our technical and administrative staffs and as a result of increased amounts of professional fees.

Curtailment of drilling

We determined in January 2007 to reduce our drilling activities for the first three months of 2007. This determination was due to a decline in oil and natural gas prices in January 2007 compared to such prices in the fourth quarter of 2006, the costs of goods and services necessary to complete our drilling activities and the resulting effect of these circumstances on our expected cash flow for the three months ended March 31, 2007. In addition, we determined to reduce our drilling activities and curtail capital expenditures until we were able to complete our New 2nd Lien Credit Facility in March 2007 in order to preserve liquidity. Also due to the reduced drilling activities described above, we recorded an expense in 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. Approximately $3.0 million of this amount was paid to Silver Oak Drilling, LLC, which is an affiliate of the Chase Group. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007, and we believe we will spend our revised 2007 exploration and development budget of approximately $183.0 million during 2007. See Recent events for a discussion of the revised 2007 exploration and development budget. There were no contract drilling fees incurred related to stacked rigs during the three months ended September 30, 2007.

Recent events

On June 27, 2007, we were notified that a natural gas processing plant through which we process and sell a portion of the production from our Shelf Properties in New Mexico was shut-down for repairs as a result of a storm. Approximately 40 MMcfe per day of our production was shut-in as a result of this plant shut-down. The plant became fully operational on July 3, 2007, and we resumed production from all of our properties that had been affected. On July 16, 2007, this plant was shut-down again for repairs. Approximately 40 MMcfe per day of our production was shut-in again as a result of this plant shut-down. The plant became fully operational on July 20, 2007, and we resumed production from all of our properties that had been affected. As a result of this plant downtime and associated gathering system interruptions and high pressure situations, our production delivery was further restricted in

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varying amounts during late July and the full months of August and September. During the quarter ended September 30, 2007, these curtailments aggregated approximately 500 MMcfe net to our interest. These production delivery restrictions were reduced significantly toward the end of September and the first of October and, as a result, we resumed full levels of production delivery during the month of October.

On August 7, 2007, we completed an initial public offering (the IPO) of our common stock. We sold 13,332,851 shares and certain shareholders, including our executive officers and members of the Chase Group, sold 7,554,256 shares of our 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, we received net proceeds of approximately $139.2 million. In conjunction with the IPO, the underwriters were granted an option to purchase from us 3,133,066 additional shares of our 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, we received net proceeds of approximately $33.8 million. The aggregate net proceeds of approximately $173.0 million received by us at closings on August 7, 2007 and August 9, 2007 were utilized in equal parts to repay a portion of the New 2nd Lien Credit Facility on August 9, 2007, and to prepay a portion of the 1st Lien Credit Facility on August 20, 2007. 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 2nd Lien Credit Facility was written off to interest expense in August 2007 in the amount of approximately $0.4 million.

On August 16, 2007, our board of directors approved an increase in our 2007 exploration and development budget in the amount of $29 million. Our 2007 exploration and development budget is comprised of the following:

(in millions)	**Original Budget**	**Revised Budget**
Drilling and recompletion opportunities in our core operating area	$119.4	$135.2
Projects in our emerging plays	15.7	28.9
Projects operated by third parties	14.2	14.2
Acquisition of leasehold acreage and other property interests	4.7	4.7
Total 2007 exploration and development budget	$154.0	$183.0

We anticipate that this incremental $29 million in our 2007 exploration and development budget will be funded by utilizing availability under our revolving credit facility.

On November 8, 2007 our board of directors approved our 2008 exploration and development budget in the amount of $250.4 million. Our 2008 exploration and development budget is comprised of the following:

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

Other than leasehold acreage and other property interests shown above, our 2007 and 2008 exploration and development budgets are exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast.

On November 8, 2007, the Compensation Committee of the Board of Directors authorized and approved amendments to certain outstanding agreements related to options to purchase our common stock that were previously awarded to our executive officers and employees in order to amend such award agreements so that the subject stock option award would constitute deferred compensation that is compliant with Section 409A of the Internal Revenue Code of 1986, as amended (the Code), or exempt from the application of Code Section 409A. As the offer to amend outstanding stock option agreements previously issued to our employees may constitute a tender offer under the Securities Exchange Act of 1934, on November 8, 2007, the Board of Directors of the Company has

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authorized commencement of a tender offer to amend the applicable outstanding stock option award agreements in the form approved by the Compensation Committee.

Generally, the amendments provide that the employee stock options, which had previously vested in connection with the combination transaction, will become exercisable in 25% increments over a four year period or upon the occurrence of certain specified events. Any employee who decides to amend their stock option award agreement will receive a bonus payment equal to $0.50 for each share of common stock subject to the amendment on January 2, 2008. Assuming all outstanding employees elect to amend their options subject to the offer, we expect to make aggregate bonus payments of approximately $275,000 to employees. Our executive officers will receive a similar offer to amend their stock option awards issued prior to the combination transaction on substantially the same terms, except executive officers will not be entitled to receive the $0.50 per share payment.

In addition, our executive officers received stock option awards in June 2006 to purchase 450,000 shares of common stock, in the aggregate, at a purchase price of $12.00 per share. We subsequently determined that the fair market value of a share of common stock as of the date of the award was $15.40. As a result, the Compensation Committee has authorized and approved an amendment to these stock option award agreements pursuant to which the exercise price of such stock options would be increased from $12.00 per share to $15.40 per share. If an executive officer accepts this offer, we have agreed to issue to the executive officer an award of the number of shares of restricted stock equal to (i) the product of $3.40 and the number of shares of common stock subject to the stock option award, divided by (ii) the fair market value of a share of common stock on the date of the award of restricted stock.

Based on our preliminary estimates, which are subject to change depending on the timing of acceptance of our offers by the employees and executive officers, we have determined that our aggregate compensation expense resulting from these proposed modifications of approximately $1.2 million will be recorded during the remainder of the year ending December 31, 2007 and during the years ending December 31, 2008, 2009 and 2010.

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Results of operations of Concho Resources Inc.

The following table presents selected financial and operating information of Concho Resources Inc. (as successor to Concho Equity Holdings Corp.) for the three and nine months ended September 30, 2007 and 2006:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
(in thousands, except price data)	(unaudited)		(unaudited)	
Oil sales	$45,685	$40,239	$128,152	$ 90,737
Natural gas sales	23,413	18,036	67,395	44,908
Total operating revenues	69,098	58,275	195,547	135,645
Operating costs and expenses	46,602	38,543	134,864	94,167
Interest, net and other revenue	8,570	8,851	28,846	20,091
Income before income taxes	13,926	10,881	31,837	21,387
Income tax expense	(5,972)	(4,351)	(13,335)	(8,664)
Net income	$ 7,954	$ 6,530	$ 18,502	$ 12,723
Production volumes:				
Oil (MBbl)	705	661	2,143	1,554
Natural gas (MMcf)	2,982	2,718	8,887	6,634
Natural gas equivalent (MMcfe)	7,211	6,683	21,747	15,956
Average prices:				
Oil, without hedges ($/Bbl)	$ 69.91	$ 65.52	$ 61.36	$ 63.20
Oil, with hedges ($/Bbl)	$ 64.82	$ 60.89	$ 59.79	$ 58.40
Natural gas, without hedges ($/Mcf)	$ 7.61	$ 6.58	$ 7.48	$ 6.75
Natural gas, with hedges ($/Mcf)	$ 7.85	$ 6.63	$ 7.58	$ 6.77
Natural gas equivalent, without hedges ($/Mcfe)	$ 9.98	$ 9.16	$ 9.10	$ 8.96
Natural gas equivalent, with hedges ($/Mcfe)	$ 9.58	$ 8.72	$ 8.99	$ 8.50

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)

Three months ended September 30, 2007, compared to three months ended September 30, 2006

Oil and gas revenues. Revenue from oil and gas operations for the three months ended September 30, 2007 were $69,098,000, a $10,823,000 (19%) increase from $58,275,000 for the three months ended September 30, 2006. This increase was due to successful drilling efforts during 2006 and 2007 coupled with substantial increases in realized oil and gas prices. Total production for the three months ended September 30, 2007 was 7,211 MMcfe, a 528 MMcfe (8%) increase from 6,683 MMcfe for the three months ended September 30, 2006. Total production during the three months ended September 30, 2007 was reduced by approximately 500 MMcfe as a result of the temporary shut-downs of a natural gas processing plant through which we process and sell a portion of our production. See Items impacting comparability of our financial results Recent events. In addition:

average realized oil prices (after giving effect to hedging activities) were $64.82 per Bbl during the three months ended September 30, 2007, an increase of 6% from $60.89 per Bbl during the three months ended September 30, 2006;

average realized natural gas prices (after giving effect to hedging activities) were $7.85 per Mcf during the three months ended September 30, 2007, an increase of 18% from $6.63 per Mcf during the three months ended September 30, 2006; and

average realized natural gas equivalent prices (after giving effect to hedging activities) were $9.58 per Mcfe during the three months ended September 30, 2007, an increase of 10% from $8.72 per Mcfe during the three months ended September 30, 2006.

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. Following is a summary of the effects of commodity hedges for the three months ended September 30, 2007 and 2006:

	Crude Oil Hedges Three months ended September 30,		Natural Gas Hedges Three months ended September 30,	
	2007 (unaudited)	2006 (unaudited)	2007 (unaudited)	2006 (unaudited)
Hedging revenue increase (decrease)	$(3,591,000)	$(3,062,000)	$ 722,000	$ 140,000
Hedged volumes (Bbls and MMBtus, respectively)	271,400	340,400	1,665,200	1,702,000
Hedged revenue increase (decrease) per hedged volume	$ (13.23)	$ (9.00)	$ 0.43	$ 0.08

During the three months ended September 30, 2007, our commodity price hedges decreased oil revenues by $3,591,000 ($5.09 per Bbl). During the three months ended September 30, 2006, our commodity price hedges decreased oil revenues by $3,062,000 ($4.63 per Bbl). The effect of the commodity price hedges in decreasing oil revenues in 2007 more than their effect of decreasing oil revenues in 2006 was the result of (1) a higher average market price of NYMEX crude oil of $75.21 per Bbl in 2007 as compared to $70.62 per Bbl in 2006, and (2) the higher hedged revenue per hedged volume in 2007 as compared to 2006, as shown in the table above, partially offset by a lower amount of hedged volumes of 271,400 Bbls in 2007 as compared to 340,400 Bbls in 2006.

During the three months ended September 30, 2007, our commodity price hedges increased gas revenues by $722,000 ($0.24 per Mcf). During the three months ended September 30, 2006, our commodity price hedges increased gas revenues by $140,000 ($0.05 per Mcf). The effect of commodity price hedges in increasing gas revenues in 2007 more than their effect of increasing gas revenues in 2006 was the result of (1) the higher hedged revenue per hedged volume in 2007 as compared to 2006, as shown in the table above and (2) a lower reference market price for natural gas of $5.47 per MMBtu in 2007 as compared to $5.93 per MMBtu in 2006, partially offset by a lower amount of hedged volumes of 1,665,200 MMBtus in 2007 as compared to 1,702,000 MMBtus in 2006.

The hedged revenue per hedged volume for natural gas in 2007 was partially reduced because we determined that all of our natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133 during the three months ended September 30, 2007. Derivative contract settlement amounts for the three months ended September 30, 2007 are reclassified from *Accumulated other comprehensive income (AOCI)* rather than recorded from the cash settlements. Cash settlements for the three months ended September 30, 2007 are recorded to *(Gain) loss on derivatives not designated as hedges*. As a result, the pre-tax amount of $722,000 was reclassified from *AOCI* to *Natural gas revenues*. The cash settlement receipts of approximately $1,286,000 are recorded in earnings under *(Gain) loss on derivatives not designated as hedges*. See Note I *Derivative financial instruments* in the condensed notes to the consolidated financial statements. Any amounts in *AOCI* as of June 30, 2007 related to these dedesignated

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hedges will remain in *AOCI* and be reclassified into earnings under *Natural gas revenues* during the periods which the hedged forecasted transaction affects earnings.

Production expenses. Production expenses (including production taxes) were $13,773,000 ($1.91 per Mcfe) for the three months ended September 30, 2007, a $3,628,000 (36%) increase from $10,145,000 ($1.52 per Mcfe) for the three months ended September 30, 2006. The increase in production expenses is due to costs associated with new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities. Lease operating expenses and workover costs comprised approximately 59% and 54% of production expenses for the three months ended September 30, 2007 and 2006, respectively. These costs per unit of production were $1.12 per Mcfe during the three months ended September 30, 2007, an increase of 36% from $0.83 per Mcfe during the three months ended September 30, 2006. This is primarily due to an increase in contract labor, subsurface pump maintenance, treating chemicals, electrical work, and well service and repair, including repair activity on a well in Gaines County, Texas in the amount of $863,000. 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% and 4% of lease operating expenses for the three months ended September 30, 2007 and 2006, respectively.

The secondary component of production expenses is production taxes and is directly related to commodity price changes. These costs comprised approximately 41% and 46% of production expenses during the three months ended September 30, 2007 and 2006, respectively. Production taxes per unit of production were $0.79 per Mcfe during the three months ended September 30, 2007, an increase of 14% from $0.69 per Mcfe during the three months ended September 30, 2006. 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 September 30, 2007 and 2006:

	Three months ended September 30,	
	2007	**2006**
(in thousands)	**(unaudited)**	**(unaudited)**
Geological and geophysical	$ 368	$ 478
Exploratory dry holes	10,557	2,809
Leasehold abandonments	880	29
Total exploration and abandonments	$11,805	$3,316

Our geological and geophysical expense, which primarily consists of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis, during the three months ended September 30, 2007 was $368,000, a decrease of $110,000 from $478,000 for the three months ended September 30, 2006. This 23% decrease is attributable to a reduction in seismic data purchased in 2007.

Our exploratory dry holes expense during the three months ended September 30, 2007 is primarily attributable to two operated exploratory wells that were unsuccessful. The costs associated with the two wells drilled in the Western Delaware Basin in Culberson County, Texas approximated $8.6 million. An additional $1.4 million was charged to exploratory dry hole costs relative to two outside operated wells in the Southeastern New Mexico Basin in Eddy County, New Mexico which were determined to be dry.

Our exploratory dry holes expense during the three months ended September 30, 2006 was primarily attributable to an outside operated exploratory well in Val Verde County, Texas that was unsuccessful.

For the three months ended September 30, 2007, we had $880,000 of leasehold abandonments of one prospect located in Edwards County, Texas. We had minimal leasehold abandonments during the three months ended September 30, 2006.

Depreciation and depletion expense. Depreciation and depletion expense was $18,003,000 ($2.50 per Mcfe) for the three months ended September 30, 2007, a decrease of $1,671,000 from $19,674,000 ($2.94 per Mcfe) for the three months ended September 30, 2006. 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.

Impairment of oil and gas properties. In accordance with SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, 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 September 30, 2007, we recognized a non-cash charge against earnings of $1,379,000, primarily related to a well drilled on acreage in Crane County, Texas. For the three months ended September 30, 2006, we recognized a non-cash charge against earnings of $2,679,000, 85% of which related to properties acquired in our Lowe Acquisition in December 2004 located primarily in Pecos County and Midland County, Texas and 15% related to a well drilled in Eddy County, New Mexico.

Contract drilling fees stacked rigs. As discussed above under Items impacting comparability of our financial results Curtailment of drilling, we determined in January 2007 to reduce our drilling activities for the first three months of 2007. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007. As a result, there were no contract drilling fees for stacked rigs incurred during the three months ended September 30, 2007.

General and administrative expenses. General and administrative expenses were $4,646,000 ($0.64 per Mcfe) for the three months ended September 30, 2007, an increase of $814,000 (21%) from $3,832,000 ($0.57 per Mcfe) for the three months ended September 30, 2006. Excluding non-cash stock-based compensation of $703,000 during the three months ended September 30, 2007 and $1,090,000 during the three months ended September 30, 2006, general and administrative expenses was $3,943,000 ($0.55 per Mcfe) for the three months ended September 30, 2007, an increase of $1,201,000 (44%) from $2,742,000 ($0.41 per Mcfe) for the three months ended September 30, 2006. The increase in general and administrative expense during the three months ended September 30, 2007 was primarily due to the increase in the size and complexity of our operations following the combination transaction and related increase in professional fees.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $222,000 and $181,000 during the three months ended September 30, 2007 and 2006, respectively. This revenue is reflected as a reduction of *General and administrative expenses* in the accompanying consolidated statements of operations.

(Gain) 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. As a result, any changes in fair value must be recorded in earnings under *(Gain) loss on derivatives not designated as hedges* and any related cash settlements are recorded to *(Gain) loss on derivatives not designated as hedges*. For the de-designated hedges for the three months ended September 30, 2007, the mark-to-market adjustment was a gain of $1,802,000 and the related cash settlement receipts was $1,286,000.

Interest expense. Interest expense was $9,054,000 for the three months ended September 30, 2007, a decrease of $130,000 from $9,184,000 for the three months ended September 30, 2006. The weighted average interest rate for the three months ended September 30, 2007 and 2006 was 7.8% and 7.7%, respectively. The weighted average debt balance during the three months ended September 30, 2007 and 2006 was approximately $415,398,000 and $480,624,000, respectively. The decrease in weighted average debt balance during the three months ended September 30, 2007 was primarily due to our paying down our credit facilities with net proceeds from the IPO. The decrease in interest expense was due to the decrease in overall debt outstanding, partially offset by a slight increase in interest rates and by $1.0 million of deferred loan fees and $0.4 million of original issue discount on the New 2nd Lien Credit Facility that were expensed during the three months ended September 30, 2007.

Income tax provisions. We recorded an income tax expense of $5,972,000 and $4,351,000 for the three months ended September 30, 2007 and 2006, respectively. The income tax expense was due to the income reported during the three months ended September 30, 2007 and 2006. The effective income tax rate for the three months ended September 30, 2007 and 2006 was 42.9% and 40.0%, respectively.

We had a net deferred tax liability of $248,212,000 and $241,670,000 at September 30, 2007 and December 31, 2006, 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 2007 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.

Nine months ended September 30, 2007, compared to nine months ended September 30, 2006

Oil and gas revenues. Revenue from oil and gas operations was $195,547,000 for the nine months ended September 30, 2007, an increase of $59,902,000 (44%) from $135,645,000 for the nine months ended September 30, 2006. This increase was primarily because of increased production as a result of the acquisition of the Chase Group Properties and secondarily due to successful drilling

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efforts during 2006 and 2007, coupled with moderate increases in realized oil and gas prices. Total production was 21,747 MMcfe for the nine months ended September 30, 2007, an increase of 5,791 MMcfe (36%) from 15,956 MMcfe for the nine months ended September 30, 2006. Total production during the nine months ended September 30, 2007 was reduced by approximately 660 MMcfe as a result of the temporary shut-downs of a natural gas processing plant through which we process and sell a portion of our production. See Items impacting comparability of our financial results Recent events. The increases in revenue and production attributable to the acquired Chase Group Properties between 2006 and 2007 were $27,806,000 and 3,397 MMcfe, respectively. In addition:

- average realized oil prices (after giving effect to hedging activities) were $59.79 per Bbl during the nine months ended September 30, 2007, an increase of 2% from $58.40 per Bbl during the nine months ended September 30, 2006;

- average realized natural gas prices (after giving effect to hedging activities) were $7.58 per Mcf during the nine months ended September 30, 2007, an increase of 12% from $6.77 per Mcf during the nine months ended September 30, 2006; and

- average realized natural gas equivalent prices (after giving effect to hedging activities) were $8.99 per Mcfe during the nine months ended September 30, 2007, an increase of 6% from $8.50 per Mcfe during the nine months ended September 30, 2006.

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. Following is a summary of the effects of commodity hedges for the nine months ended September 30, 2007 and 2006:

	Crude Oil Hedges Nine months ended September 30,		Natural Gas Hedges Nine months ended September 30,	
	2007 (unaudited)	**2006 (unaudited)**	**2007 (unaudited)**	**2006 (unaudited)**
Hedging revenue increase (decrease)	$(3,347,000)	$(7,456,000)	$ 909,000	$ 114,000
Hedged volumes (Bbls and MMBtus, respectively)	805,350	740,100	4,817,400	3,745,500
Hedged revenue increase (decrease) per hedged volume	$ (4.16)	$ (10.07)	$ 0.21	$ 0.03

During the nine months ended September 30, 2007, our commodity price hedges decreased oil revenues by $3,347,000 ($1.56 per Bbl). During the nine months ended September 30, 2006, our commodity price hedges decreased oil revenues by $7,456,000 ($4.80 per Bbl). The effect of the commodity price hedges in decreasing oil revenues during the nine months ended September 30, 2007 less than their effect of decreasing oil revenues during the nine months ended September 30, 2006 was the result of (1) a lower average market price of NYMEX crude oil of $66.21 per Bbl in 2007 as compared to $68.23 per Bbl in 2006, and (2) the lower hedged revenue per hedged volume in 2007 as compared to 2006, as shown in the table above, partially offset by a larger amount of hedged volumes of 805,350 Bbls in 2007 as compared to 740,100 Bbls in 2006.

During the nine months ended September 30, 2007, our commodity price hedges increased gas revenues by $909,000 ($0.10 per Mcf). During the nine months ended September 30, 2006, our commodity price hedges increased gas revenues by $114,000 ($0.02 per Mcf). The effect of commodity price hedges in increasing gas revenues in 2007 more than their effect of increasing gas revenues in 2006 was the result of (1) a higher amount of hedged volumes of 4,817,400 MMBtus in 2007 as compared to 3,745,500 MMBtus in 2006, (2) the higher hedged revenue per hedged volume in 2007 as compared to 2006, as shown in the table above, and (3) a lower reference market price for natural gas of $6.13 per MMBtu in 2007 as compared to $6.21 per MMBtu in 2006.

The hedged revenue per hedged volume for natural gas in 2007 was partially reduced because we determined that all of our natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133 during the three months ended September 30, 2007. Derivative contract settlement amounts for the three months ended September 30, 2007 are reclassified from *AOCI* rather than recorded from the cash settlements. Cash settlements for the three months ended September 30, 2007 are recorded to *(Gain) loss on derivatives not designated as hedges*. As a result, the pre-tax amount of $722,000 was reclassified from *AOCI* to *Natural gas revenues*. The cash settlement receipts of approximately $1,286,000 are recorded in earnings under *(Gain) loss on derivatives not designated as hedges*. The cash settlement receipts of approximately $187,000 on these same natural gas commodity contracts during the six months ended June 30, 2007 (the periods in which these contracts qualified to use hedge accounting), are recorded in *Natural gas revenues*. See Note I *Derivative financial instruments* in the condensed notes to the consolidated financial statements. Any amounts in *AOCI* as of June 30, 2007 related to these dedesignated hedges will remain in *AOCI* and be reclassified into earnings under *Natural gas revenues* during the periods which the hedged forecasted transaction occurs.

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Production expenses. Production expenses (including production taxes) were $37,925,000 ($1.74 per Mcfe) for the nine months ended September 30, 2007, an increase of $12,583,000 (50%) from $25,342,000 ($1.59 per Mcfe) for the nine months ended September 30, 2006. The increase in production expenses is due to: (1) production expenses associated with the Chase Group Properties acquired in February 2006 of approximately $2,933,000, (2) production expenses associated with new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities, and (3) an increase in repair activity on a well in Gaines County, Texas in the amount of $881,000. Lease operating expenses and workover costs comprised approximately 59% and 57% of production expenses for the nine months ended September 30, 2007 and 2006, respectively. These costs per unit of production were $1.03 per Mcfe during the nine months ended September 30, 2007, an increase of 13% from $0.91 per Mcfe during the nine months ended September 30, 2006. 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 5% of lease operating expenses for the nine months ended September 30, 2007 and 2006, respectively.

The secondary component of production expenses is production taxes and is directly related to commodity price changes. These costs comprised approximately 41% and 43% of production expenses during the nine months ended September 30, 2007 and 2006, respectively. Production taxes per unit of production were $0.72 per Mcfe during the nine months ended September 30, 2007, an increase of 6% from $0.68 per Mcfe during the nine months ended September 30, 2006. 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 nine months ended September 30, 2007 and 2006:

	Nine months ended September 30,	
(in thousands)	**2007 (unaudited)**	**2006 (unaudited)**
Geological and geophysical	$ 993	$1,513
Exploratory dry holes	16,222	3,172
Leasehold abandonments and other	895	32
Total exploration and abandonments	$18,110	$4,717

Our geological and geophysical expense, which primarily consists of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis, during the nine months ended September 30, 2007 was $993,000, a decrease of $520,000 from $1,513,000 for the nine months ended September 30, 2006. This 34% decrease is primarily attributable to a data license and a core analysis purchased in the first quarter of 2006.

Our exploratory dry holes expense during the nine months ended September 30, 2007 is primarily attributable to five operated exploratory wells that were unsuccessful. The costs associated with three of these wells drilled in the Western Delaware Basin in Culberson County, Texas approximated $11.7 million. Another of these wells, which was drilled in the Southeastern New Mexico Basin in Lea County, New Mexico, had costs of approximately $2.3 million. An additional $0.8 million was charged to exploratory dry hole costs relative to a target zone in the fifth of these wells in the Southeastern New Mexico Basin in Eddy County, New Mexico which was determined to be dry. Exploration expense of $1.4 million related to two outside operated wells located in Eddy County, New Mexico was also recorded.

Of our exploratory dry holes expense during the nine months ended September 30, 2006, $2.6 million was attributable to one unsuccessful outside operated exploratory well located in Val Verde County, Texas.

For the nine months ended September 30, 2007, we recorded $895,000 of leasehold abandonments, $880,000 of which was related to one prospect located in Edwards County, Texas. We had minimal leasehold abandonments during the nine months ended September 30, 2006.

Depreciation and depletion expense. Depreciation and depletion expense was $55,036,000 ($2.53 per Mcfe) for the nine months ended September 30, 2007, an increase of $12,866,000 from $42,170,000 ($2.64 per Mcfe) for the nine months ended September 30, 2006. The increase in depreciation and depletion expense was primarily due to the acquisition of the Chase Group Properties and related acquisition costs associated with the combination transaction. 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.

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 nine months ended September 30, 2007, we recognized a non-cash charge against earnings of $4,577,000, 44% of which related to a well drilled on acreage in Schleicher County, Texas, 28% of which related to a well drilled in Crane County, Texas and 8% of which related to a well drilled on acreage in Mountrail County, North Dakota. Of the total amount, $169,000 was related to the Chase Group Properties. For the nine months ended September 30, 2006, we recognized a non-cash charge against earnings of $5,762,000, 42% of which related to a property acquired in our Lowe Acquisition in December 2004 located in Pecos County, Texas, 18% related to a well drilled on acreage in Lea County, New Mexico and 7% of which related to a property drilled in Eddy County, New Mexico.

Contract drilling fees stacked rigs. As discussed above under Items impacting comparability of our financial results Curtailment of drilling, 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 $4,269,000 for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. No additional costs were incurred during the three months ended September 30, 2007. 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 $16,567,000 ($0.76 per Mcfe) for the nine months ended September 30, 2007, an increase of $523,000 (3%) from $16,044,000 ($1.01 per Mcfe) for the nine months ended September 30, 2006. Excluding non-cash stock-based compensation of $2,656,000 during the nine months ended September 30, 2007 and $8,041,000 during the nine months ended September 30, 2006, general and administrative expenses was $13,911,000 ($0.64 per Mcfe) for the nine months ended September 30, 2007, an increase of $5,908,000 (74%) from $8,003,000 ($0.50 per Mcfe) for the nine months ended September 30, 2006. The increase in general and administrative expenses during the nine months ended September 30, 2007 was primarily due to the increase in the size and complexity of our operations following the combination transaction and related increase in professional fees. In addition, annual bonuses in the aggregate amount of $2,529,000 were paid to the officers and employees in April 2007 as compared to $907,000 aggregate bonuses paid to employees in February 2006, all of which were approved by the Compensation Committee of our board of directors.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $852,000 and $602,000 during the nine months ended September 30, 2007 and 2006, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

(Gain) 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. As a result, any changes in fair value must be recorded in earnings under *(Gain) loss on derivatives not designated as hedges* and any related cash settlements are recorded to *(Gain) loss on derivatives not designated as hedges*. For the three months since de-designation beginning on July 1, 2007, the mark-to-market adjustment was a gain of $1,802,000 and the related cash settlement receipts was approximately $1,286,000.

Interest expense. Interest expense was $29,803,000 for the nine months ended September 30, 2007, an increase of $8,805,000 from $20,998,000 for the nine months ended September 30, 2006. The weighted average interest rate for the nine months ended September 30, 2007 and 2006 was 7.8% and 7.4%, respectively. The weighted average debt balance during the nine months ended September 30, 2007 and 2006 was approximately $472,360,000 and $378,323,000, respectively. The increase in weighted average debt balance during the nine months ended September 30, 2007 was primarily due to our borrowing $400.0 million to fund the cash portion of the combination transaction on February 27, 2006, and additional borrowings to fund our drilling activities, partially offset by 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. The increase in interest expense is due to a slight increase in the weighted average interest rate and the acceleration of deferred loan cost amortization and original issue discount amortization. In March 2007, we reduced the 1st Lien Credit Facility borrowing base by $100.0 million, or 21 percent, resulting in accelerated amortization of $0.8 million, and the full repayment of the 2nd Lien Credit Facility resulting in accelerated amortization of $0.4 million. The prepayment of $86.6 million on the New 2nd Lien Credit Facility in August 2007 resulted in accelerated amortization of $1.0 million in deferred loan costs and $0.4 million in original issue discount.

Income tax provisions. We recorded income tax expense of $13,335,000 and $8,664,000 for the nine months ended September 30, 2007 and 2006, respectively. The income tax expense was due to the income reported during the nine months ended September 30, 2007 and 2006. The effective income tax rate for the nine months ended September 30, 2007 and 2006 was 41.9% and 40.5%, respectively.

We had a net deferred tax liability of $248,212,000 and $241,670,000 at September 30, 2007 and December 31, 2006, 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 2007 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 for the nine months ended September 30, 2007 have been cash flows generated from operating activities and financing provided by our bank credit facilities. As discussed in Items impacting comparability of our financial results Recent events, in August 2007 we received aggregate net proceeds of $173.0 million from the sale of common stock and utilized such proceeds to repay a portion of our outstanding indebtedness. 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 revised 2007 exploration and development budget.

Cash flow from operating activities

Our net cash provided by operating activities was $102.9 million and $58.9 million for the nine months ended September 30, 2007 and 2006, respectively. The increase in operating cash flows during the nine months ended September 30, 2007 was principally due to the increase in oil and gas sales, net of production costs for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006, as a result of our successful development and exploratory drilling program and to the Chase Group Properties that we acquired in the combination transaction in February 2006, together with moderate increases in realized oil and gas prices received.

Cash flow used in investing activities

During the nine months ended September 30, 2007 and 2006, we invested $114.2 million and $536.7 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 nine months ended September 30, 2006, primarily due to the $409 million cash portion of the consideration we paid to the Chase Group in the combination transaction. We temporarily reduced our drilling activities and curtailed capital expenditures during the three months ended March 31, 2007 and a portion of the three months ended June 30, 2007, until we were able to complete the New 2nd Lien Credit Facility in March 2007 in order to preserve liquidity. See Items impacting comparability of our financial results Curtailment of drilling above.

Cash flow from financing activities

Net cash provided by financing activities was $30.8 million and $469.8 million for the nine months ended September 30, 2007 and 2006, respectively. Cash provided by financing activities in the nine months ended September 30, 2006 was primarily due to borrowings under our revolving credit facility to fund the approximate $409 million cash portion of the consideration paid to the Chase Group pursuant to the combination transaction and proceeds from private issuances of equity in our company. During the nine months ended September 30, 3007, proceeds from the New 2nd Lien Credit Facility were used to repay a portion of the amount outstanding on the 1st Lien Credit Facility and proceeds from the IPO were used to partially repay amounts outstanding on the 1st Lien Credit Facility and New 2nd Lien Credit Facility.

Bank credit facilities

We have two separate bank credit facilities. The first bank credit facility is our Credit Agreement, dated as of February 24, 2006, with JPMorgan Securities Inc. as the administrative agent for a group of lenders that provides a revolving line of credit having a maximum facility amount of $750 million, which we refer to as the revolving credit facility. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of the maximum facility amount of $750 million or the borrowing base established by the lenders. As of September 30, 2007, the borrowing base under our revolving credit facility was $375 million. As of September 30, 2007, the principal amount outstanding under our revolving credit facility was $234.0 million. In February 2006, we incurred borrowings of approximately $421.0 million under our revolving credit facility in connection with the combination transaction to pay the cash purchase price of $400.0 million to the Chase Group, $15.9 million to repay the balance on the prior revolving credit facility of Concho Equity Holdings Corp. and approximately $5.1 million for bank fees and legal costs associated with our revolving credit facility. We also incurred borrowings of approximately $8.9 million in May 2006 in connection with the purchase of additional working interests in the Chase Group Properties pursuant to the combination transaction from persons associated with the Chase Group. The remaining borrowings under our revolving credit facility during 2006 and the nine months ended September 30, 2007 were used for working capital and to fund a portion of our exploration and development drilling program. As mentioned in Items impacting comparability of our financial results Recent Events, we repaid $86.6 million of this facility on August 20, 2007 with proceeds from our IPO.

The second bank credit facility is our Second Lien Credit Agreement, dated as of 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, which we refer to as 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 proceeds of $199.0 million to repay the $39.8 million outstanding under our prior term loan facility, to reduce the outstanding balance under our revolving credit facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes. As mentioned in Items impacting comparability of our financial results Recent Events, we prepaid $86.6 million of this facility on August 9, 2007 with proceeds from our IPO.

Revolving credit facility. The revolving credit facility allows us to borrow, repay and reborrow amounts available under the revolving credit facility. 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 revolving credit facility is re-determined at least semi-annually. The revolving credit facility matures on February 24, 2010, and borrowings under our revolving credit facility 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 revolving credit facility, plus an applicable margin ranging from 100 to 225 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 revolving credit facility bore interest at 6.83% per annum as of September 30, 2007. We pay quarterly commitment fees under our revolving 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 revolving credit facility are secured by a first lien on substantially all of our assets and properties. Our revolving 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 revolving credit facility also requires us to maintain certain ratios as defined and further described in our revolving credit facility, 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 revolving credit facility, we had a one-time requirement to enter into hedging agreements 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 September 30, 2007, we were in compliance with all such covenants.

New 2nd Lien Credit Facility. The New 2nd Lien Credit Facility provides a $200 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 375 basis points or (2) the prime rate, plus an applicable margin of 225 basis points. Upon prepayment of a portion of the New 2nd Lien Credit Facility on August 9, 2007 from proceeds from the completion of the IPO, the interest rate under any of the New 2nd Lien Credit Facility outstanding increased, at our option, to (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 $500,000 of the New 2nd Lien Credit Facility 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 9.76% per annum as of September 30, 2007. We have the right to prepay the outstanding balance under the New 2nd Lien Credit Facility 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. The prepayment made on August 9, 2007 was not subject to a prepayment penalty. As a result of the partial repayment of this facility on August 9, 2007, a pro rata portion of the deferred loan costs associated with our 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 our New 2nd Lien Credit Facility was written off to interest expense in August 2007 in the amount of approximately $0.4 million.

Borrowings under the New 2nd Lien Credit Facility are secured by a second lien on the same assets as are securing our revolving credit facility, which liens are subordinated to liens securing our revolving credit agreement. The New 2nd Lien Credit Facility also contains various restrictive financial covenants and compliance requirements that are similar to those contained in the revolving credit agreement, including the maintenance of certain financial ratios.

Future capital expenditures and commitments

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.

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $183 million for exploration and development expenditures during the year ending December 31, 2007 as follows:

(in millions)	Amount
Drilling and recompletion opportunities in our core operating area	$ 135.2
Projects in our emerging plays	28.9
Projects operated by third parties	14.2
Acquisition of leasehold acreage and other property interests	4.7
Total 2007 exploration and development budget	$ 183.0

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 and availability under our revolving credit facility will be sufficient to satisfy our 2007 exploration and development budget. 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.

Hedging

We account for derivative instruments in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended. The specific accounting treatment for changes in the market value of the derivative instruments used in hedging activities is determined based on the designation of the derivative instruments as a cash flow or fair value hedge and effectiveness of the derivative instruments. Certain of our derivative contracts related to oil production entered into prior to 2007 are accounted for as cash flow hedges. As described below, certain natural gas derivative contracts were originally designated as cash flow hedges, but because of a change in the correlation between the underlying natural gas production and the index referenced in the derivative contracts, we have discontinued hedge accounting related to natural gas contracts as of July 1, 2007. Management has not and does not currently intend to designate or account for derivative contracts entered into subsequent to June 30, 2007 as cash flow hedges.

We have utilized fixed-price contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price physical delivery contracts, we receive the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil or natural gas, as applicable, is less than the ceiling strike price and greater than the floor strike price, we receive the market price. If the market price of crude oil or natural gas, as applicable, exceeds the ceiling strike price or falls below the floor strike price, we receive the applicable collar strike price.

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, Accounting for Derivative Instruments and Hedging Activities, as amended (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. In prior quarters, prices received for our natural gas have been highly correlated with the Inside FERC El Paso Natural Gas index (the Index) the Index referenced in all of our 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 our 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 we received for our 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 prospectively hedge accounting for an existing hedge if the hedge is no longer highly effective. Hedge accounting must be discontinued regardless of whether we believe 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, is considered the last date our natural gas hedges were highly effective, and we must discontinue hedge accounting during the three months ended September 30, 2007 and all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges will be 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, will remain in *AOCI* and be reclassified into earnings under *Natural gas revenues,* during the periods which the hedged forecasted transaction affects earnings.

Due to the fact that this correlation relationship is expected to continue in the future on the gas produced from the properties originally identified in our hedge documentation in 2004, 2006 and 2007, we do not intend to attempt to re-designate these natural gas derivatives as cash flow hedges in future periods; rather, they will be accounted for as described above through the remaining derivative contract term.

On September 20, 2007, we entered into four 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 1,000 Bbls per day each with various fixed prices. 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*.

At September 30, 2007, we have an oil price collar and oil price swaps that settle on a monthly basis covering future oil production from October 1, 2007 through December 31, 2009. The volumes are detailed in the table below. Subsequent to September 30, 2007, oil futures prices have increased significantly and continue to exceed the oil price collar cap of $41.75 and have risen to a level that exceeds the weighted average price swap fixed price of $70.65. The average futures NYMEX price for the three months ended September 30, 2007, was $75.33. As of October 31, 2007, the NYMEX futures price was $94.53. At this level, we will continue to remit the excess of the average monthly NYMEX futures price for each settlement period over the oil collar cap price of $41.75 and the weighted average price swap fixed price of $70.65. While these payments should not significantly affect our cash flow since (1) payments made to counterparties to these contracts should be substantially offset by increased commodity prices received on the sale of our production and (2) only a portion of the total contract volume settles each month. The increase in oil prices, should it continue, will negatively affect the fair value of our commodities contracts as recorded in our balance sheet at December 31, 2007, during future periods and, consequently, our reported net earnings. Changes in the recorded fair value of certain of our commodity derivatives are marked to market through earnings and are likely to result in substantial charges to earnings for the decrease in the fair value of these contracts during the fourth quarter of 2007. If oil prices continue to increase, this negative effect on earnings will become more significant. We are currently unable to estimate the effects on earnings in the fourth quarter of 2007, but the effects may be substantial.

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The table below provides the volumes and related data associated with our oil and natural gas derivatives as of September 30, 2007:

	Fair Market Value Asset / (Liability) (in thousands)	Aggregate remaining volume	Daily volume	Index price	Contract period
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price collar	$ (2,278)	59,800	650	$37.95 - $41.75[(a)]	10/1/07 - 12/31/07
Price swap	(2,570)	211,600	2,300	$67.85[(a)]	10/1/07 - 12/31/07
Price swap	(7,668)	951,600	2,600	$67.50[(a)]	1/1/08 - 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	735	1,472,000	16,000	$5.98 - $9.75 [(b)(c)]	10/1/07 - 12/31/07
Price collar	1,740	4,941,000	13,500	$6.50-$9.35[(b)]	1/1/08 - 12/31/08
Price swap	257	193,200	2,100	$7.40[(b)]	10/1/07 - 12/31/07
Derivatives not designated as cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	(33)	732,000	2,000	$75.78[(a)(c)]	1/1/08 - 12/31/08
Price swap	71	730,000	2,000	$72.84[(a)(c)]	1/1/09 - 12/31/09
Net liability	$ (9,746)				

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

(b)

The index prices for the natural gas price collars and price swaps are based on the Inside FERC-El Paso Permian Basin first-of-the-month spot price.

(c) Amounts disclosed represent weighted average prices.

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Contractual obligations and commitments

We had the following contractual obligations and commitments as of September 30, 2007:

(in thousands)	Total	Payments due by period Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[(a)]	$346,400	$ 2,000	$238,000	$106,400	$
Operating lease obligation[(b)]	2,637	433	867	867	470
Daywork drilling contracts[(c)]	18,410	18,410			
Employment agreements with executive officers[(d)]	2,828	1,700	1,128		
Asset retirement obligations[(e)]	7,276	1,005	144	213	5,914
Total contractual cash obligations	$377,551	$23,548	$240,139	$107,480	$6,384

(a) See Note J *Long-term debt* to our consolidated financial statements.

(b) Operating lease obligation is for office space.

(c) Consists of daywork drilling contracts related to five drilling rigs contracted for a portion of 2007 and a portion of 2008. See Note K *Commitments and contingencies* to our consolidated financial statements.

(d) 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 in the discretion of the board of directors.

(e) Amounts represent costs related to expected oil and gas property abandonments related to proved reserves by period, net of any future accretion.

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 nine months ended September 30, 2007. See our disclosure of critical accounting policies in the consolidated financial statements on Form S-1 for the year ended December 31, 2006 contained in our Prospectus dated August 2, 2007 and filed with the SEC pursuant to Rule 424 (b) on August 3, 2007.

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Recent accounting pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement . This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We will adopt SFAS No. 157 effective January 1, 2008. We are currently evaluating the impact of SFAS No. 157.

In February 2007, the FASB issued SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115, (FAS 159) which will become effective in 2008. FAS 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 will adopt this statement January 1, 2008, and we do not expect that we will elect the fair value option for any of our eligible financial instruments and other items.

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 do not intend to adopt EITF Issue 06-11 prior to the required effective date of January 1, 2008. We do not expect the adoption of EITF Issue 06-11 to have 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.

The FASB issued FSP FIN No. 48-1, Definition of *Settlement* in FASB Interpretation No. 48, to clarify when a tax position is effectively settled. This guidance is important 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. The FSP 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. We do not expect the adoption of this standard to have a significant effect on our financial statements.

Inflation

Historically, general inflationary trends have not had a material effect on our operating results. However, we have recently experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increase in drilling activity and competitive pressures resulting from higher oil and natural gas prices in recent years.

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 Prospectus dated August 2, 2007 and filed with the SEC pursuant to Rule 424 (b) on August 3, 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 prospectus dated August 2, 2007 and filed with the SEC pursuant to Rule 424 (b) on August 3, 2007, as well as with the consolidated financial statements and notes thereto included in this quarterly report on Form 10-Q.

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.

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.

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. 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. In this manner, we reduce credit risk.

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 partially reduce price risk caused by these market fluctuations, we have hedged approximately 75% of our forecasted oil and natural gas production through December 31, 2008, attributable to our proved developed producing reserves as of December 31, 2005, through the utilization of derivatives, including zero-cost collars and fixed price contracts. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources Hedging. 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, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133), as a result of the historical relationship between the hedging instrument and the forecasted transaction no longer being highly correlated. This lack of correlation is due to the substantial component of natural gas liquids in natural gas produced from our New Mexico Shelf assets. Prices received for natural gas liquids are not highly correlated to the price of natural gas, but are more correlated to the price of oil. During the third quarter of 2007, the price of oil and natural gas liquids rose substantially and at a significantly higher rate than the corresponding change in the index on which our natural gas derivatives are based. This resulted in a decrease in the correlation between the prices received and the derivative index below the level required for cash flow hedge accounting. If oil prices remain at current levels or continue to increase, this negative effect on earnings will become more significant. We are currently unable to estimate the effects on earnings in the fourth quarter of 2007, but the effects may be substantial.

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

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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 $346.4 million outstanding under our revolving credit facility at September 30, 2007. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $3.5 million and a corresponding decrease in net income before income tax.

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 September 30, 2007, 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 1A. Risk factors

For a discussion of our potential risks and uncertainties, see the information under the heading Risk factors in our prospectus dated August 2, 2007, filed with the SEC in accordance with Rule 424(b) of the Securities Act on August 3, 2007, which is accessible on the SEC s website at www.sec.gov. There have been no material changes to the risk factors disclosed in the prospectus.

Item 6. Exhibits

Exhibit Number	Exhibit
10.1	Indemnification Agreement dated August 21, 2007, by and between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.2	Indemnification Agreement dated August 21, 2007, by and between Concho Resources Inc. and Ray M. Poage (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.3	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.3 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.4	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.4 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)

10.5	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and David W. Copeland (filed as Exhibit 10.5 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)

Exhibit Number	Exhibit
10.6	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Curt F. Kamradt (filed as Exhibit 10.6 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.7	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.7 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.8	First Amendment to Employment Agreement, dated August 31, 2007, by and between Concho Resources Inc. and David M. Thomas III (filed as Exhibit 10.9 to the Company s Quarterly Report on Form 10-Q filed on September 10, 2007, 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: November 14, 2007

By /S/ Timothy A. Leach

Timothy A. Leach
Chairman and Chief Executive Officer

By /S/ Curt F. Kamradt

Curt F. Kamradt
Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)