CONCHO RESOURCES INC
Form 10-Q
November 13, 2008

Table of Contents

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, 2008

or

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

For the transition period from __________ to __________

Commission file number: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0818600**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
550 West Texas Avenue, Suite 100 Midland, Texas	**79701**
(Address of principal executive offices)	(Zip code)

(432) 683-7443

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

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

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

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

Number of shares of the registrant s common stock outstanding at November 12, 2008: 84,706,291 shares.

TABLE OF CONTENTS

Table of Contents

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, as amended, (the Securities Act) and Section 21E of the Securities Exchange Act of 1934, as amended, (the Exchange Act) 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 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 report, the words could, believe, anticipate, intend, estimate, ex may, continue, predict, potential, project and similar expressions are intended to identify forward-looking statem although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and elsewhere in this report 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;
- the estimated quantities of crude oil and natural gas reserves;
- technology;
- our financial strategy;
- our crude oil and natural gas realized prices;
- the timing and amount of our future production of crude oil and natural gas;
- the amount, nature and timing of our capital expenditures;
- our drilling of wells;
- our competition and government regulations;
- the marketing of our crude oil and natural gas;
- our exploitation or property acquisitions;
- the costs of exploiting and developing our properties and conducting other operations;
- general economic and business conditions;
- our cash flow and anticipated liquidity;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this 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 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 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 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.

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements (Unaudited)

Table of Contents

Concho Resources Inc.
Consolidated Balance Sheets
Unaudited

(in thousands, except share and per share data)	September 30, 2008	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 54,370	$ 30,424
Accounts receivable, net of allowance for doubtful accounts:		
Oil and gas	54,851	36,735
Joint operations and other	67,507	21,183
Related parties	548	
Derivative instruments	11,965	1,866
Deferred income taxes	6,983	13,502
Prepaid costs and other	5,398	4,273
Total current assets	201,622	107,983
Property and equipment, at cost:		
Oil and gas properties, successful efforts method	2,580,508	1,555,018
Accumulated depletion and depreciation	(244,175)	(167,109)
Total oil and gas properties, net	2,336,333	1,387,909
Other property and equipment, net	13,593	7,085
Total property and equipment, net	2,349,926	1,394,994
Deferred loan costs, net	16,558	3,426
Inventory	22,790	1,459
Intangible asset, net operating rights	48,524	
Noncurrent derivative instruments	23,981	
Other assets	373	367
Total assets	$ 2,663,774	$ 1,508,229
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 19,419	$ 14,222
Related parties	1,062	2,119
Other current liabilities:		
Bank overdrafts	4,697	5,651
Revenue payable	22,194	14,494
Accrued and prepaid drilling costs	145,861	39,276
Derivative instruments	29,870	36,414
Income taxes payable	3,584	29

Current portion of long-term debt		2,000
Other current liabilities	27,859	14,437
Total current liabilities	254,546	128,642
Long-term debt	635,000	325,404
Noncurrent derivative instruments	24,857	10,517
Deferred income taxes	543,239	259,070
Asset retirement obligations and other long-term liabilities	17,387	9,198
Commitments and contingencies (Note L)		
Stockholders equity:		
Preferred stock, $0.001 par value; 10,000,000 shares authorized; and none issued and outstanding at September 30, 2008 and December 31, 2007		
Common stock, $0.001 par value; 300,000,000 authorized; 84,620,765 and 75,832,310 shares issued at September 30, 2008 and December 31, 2007, respectively	85	76
Additional paid-in capital	1,006,496	752,380
Notes receivable from employees		(330)
Retained earnings	187,340	37,467
Accumulated other comprehensive loss	(5,051)	(14,195)
Treasury stock, at cost; 3,142 and zero shares of treasury stock at September 30, 2008 and December 31, 2007, respectively	(125)	
Total stockholders equity	1,188,745	775,398
Total liabilities and stockholders equity	$ 2,663,774	$ 1,508,229

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

1

Table of Contents

Concho Resources Inc.
Consolidated Statements of Operations
Unaudited

(in thousands, except per share amounts)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Operating revenues:				
Oil sales	$ 130,600	$ 45,685	$ 301,826	$ 128,152
Natural gas sales	39,857	23,413	112,725	67,395
Total operating revenues	170,457	69,098	414,551	195,547
Operating costs and expenses:				
Oil and gas production	27,041	13,773	65,915	37,925
Exploration and abandonments	16,824	11,805	20,288	18,110
Depreciation, depletion and amortization	32,528	18,003	75,822	55,036
Accretion of discount on asset retirement obligations	270	106	571	334
Impairments of long-lived assets	2,758	1,379	2,827	4,577
General and administrative (including non-cash stock-based compensation of $1,925 and $702 for the three months ended September 30, 2008 and 2007, respectively, and $4,954 and $2,656 for the nine months ended September 30, 2008 and 2007, respectively)	10,778	4,646	27,044	16,567
Bad debt expense	1,106		2,905	
Contract drilling fees stacked rigs				4,269
Ineffective portion of cash flow hedges	(416)	(22)	(1,336)	1,134
Gain on derivatives not designated as hedges	(163,312)	(3,088)	(43,678)	(3,088)
Total operating costs and expenses	(72,423)	46,602	150,358	134,864
Income from operations	242,880	22,496	264,193	60,683
Other income (expense):				
Interest expense	(10,255)	(9,054)	(19,755)	(29,803)
Other, net	334	484	1,665	957
Total other expense	(9,921)	(8,570)	(18,090)	(28,846)
Income before income taxes	232,959	13,926	246,103	31,837
Income tax expense	(91,031)	(5,972)	(96,230)	(13,335)
Net income	141,928	7,954	149,873	18,502
Preferred stock dividends				(45)
Net income applicable to common shareholders	$ 141,928	$ 7,954	$ 149,873	$ 18,457
Basic earnings per share:				
Net income per share	$ 1.75	$ 0.12	$ 1.93	$ 0.30

Weighted average shares used in basic earnings per share	81,288	69,067	77,489	60,648
Diluted earnings per share:				
Net income per share	$ 1.72	$ 0.11	$ 1.90	$ 0.29
Weighted average shares used in diluted earnings per share	82,724	69,913	78,945	62,858

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

Table of Contents

Concho Resources Inc.
Consolidated Statement of Stockholders Equity
Unaudited

(in thousands)	Common stock Shares	Common stock Amount	Additional paid-in capital	Notes receivable from employees	Retained earnings	Accumulated other comprehensive loss	Treasury stock Shares	Treasury stock Amount	Total stockholders equity
BALANCE AT DECEMBER 31, 2007	75,832	$ 76	$ 752,380	$ (330)	$ 37,467	$ (14,195)		$	$ 775,398
Comprehensive income									
Net income					149,873				149,873
Deferred hedge losses, net of taxes of $7,013						(10,909)			(10,909)
Net settlement losses included in earnings, net of taxes of $12,891						20,053			20,053
Total comprehensive income									159,017
Issuance of common stock	8,304	8	242,418						242,426
Stock options exercised	430	1	3,860						3,861
Restricted stock issued as stock-based compensation	98		1,578						1,578
Cancellation of restricted stock	(43)								
Stock-based compensation for stock options			3,376						3,376
Excess tax benefits related to stock-based compensation			2,884						2,884
Proceeds from notes receivable employees				333					333
				(3)					(3)

Accrued interest employee notes									
Purchase of treasury stock							3	(125)	(125)
BALANCE AT SEPTEMBER 30, 2008	84,621	$ 85	$ 1,006,496	$	$ 187,340	$ (5,051)	3	$ (125)	$ 1,188,745

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

3

Table of Contents

Concho Resources Inc.
Consolidated Statements of Cash Flows
Unaudited

(in thousands)	Nine Months Ended September 30, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 149,873	$ 18,502
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	75,822	55,036
Impairments of long-lived assets	2,827	4,577
Accretion of discount on asset retirement obligations	571	334
Exploration expense, including dry holes	17,860	17,117
Non-cash compensation expense	4,954	2,656
Bad debt expense	2,905	
Deferred income taxes	86,908	11,460
Gain on sale of assets	(777)	
Ineffective portion of cash flow hedges	(1,336)	1,134
Gain on derivatives not designated as hedges	(43,678)	(3,088)
Dedesignated cash flow hedges reclassified from accumulated other comprehensive income (loss)	260	(722)
Other non-cash items	2,749	3,523
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	26,209	11,355
Prepaid costs and other	(1,035)	230
Inventory	(14,985)	(95)
Accounts payable	(12,472)	(9,230)
Revenue payable	6,982	(5,325)
Other current liabilities	16,992	(4,757)
Income taxes payable	(1,229)	225
Net cash provided by operating activities	319,400	102,932
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and gas properties	(213,666)	(113,936)
Acquisition of oil and gas properties, businesses and other assets	(586,925)	(256)
Additions to other property and equipment	(6,711)	(2,218)
Proceeds from the sale of oil and gas properties	1,034	96
Settlements received (paid) on derivatives not designated as hedges	(29,170)	1,286
Net cash used in investing activities	(835,438)	(115,028)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt	767,800	283,600
Payments of long-term debt	(460,700)	(433,700)
Exercise of stock options	3,861	
Excess tax benefit from stock-based compensation	2,884	

Net proceeds from issuance of common stock	242,426	173,002
Payments of preferred stock dividends		(132)
Proceeds from repayment of employee notes	333	10,644
Payments for loan origination costs	(15,541)	(2,572)
Purchase of treasury stock	(125)	
Bank overdrafts	(954)	
Net cash provided by financing activities	539,984	30,842
Net increase in cash and cash equivalents	23,946	18,746
Cash and cash equivalents at beginning of period	30,424	1,122
Cash and cash equivalents at end of period	$ 54,370	$ 19,868
SUPPLEMENTAL CASH FLOWS:		
Cash paid for interest and fees, net of $1,090 and $2,160 capitalized interest	$ 16,164	$ 32,322
Cash paid for income taxes	$ 5,964	$ 2,050

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

4

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

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

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

In the Combination, CEHC s shareholders received 23,767,691 shares of common stock of the Company 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 H. In addition, the Chase Group transferred the Chase Group Properties to the Company in exchange for cash in the aggregate amount of approximately $409 million and 34,794,638 shares of the Company s common stock. In connection with the Company s initial public offering and secondary public offering (both described below), the Chase Group sold a total of 18,638,014 shares of the Company s common stock. At September 30, 2008 and December 31, 2007, the Chase Group owned approximately 10 percent and 21 percent, respectively, of the total outstanding common stock of the Company.

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

Initial public offering. On August 7, 2007, the Company completed an initial public offering (the IPO) of its common stock. The Company sold 13,332,851 shares of its common stock in the IPO and certain shareholders, including its executive officers and certain members of the Chase Group, sold 7,554,256 shares of the Company s common stock 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 the Company s 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 to reduce bank debt.

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

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

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

Interim financial statements. The accompanying consolidated financial statements of the Company have not been audited by the Company s independent registered public accounting firm, except that the consolidated balance sheet at December 31, 2007 is derived from audited financial statements. In the opinion of management, the accompanying financial statements reflect all adjustments

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

necessary to present fairly the Company s financial position at September 30, 2008, its results of operations for the three and nine months ended September 30, 2008 and 2007 and its cash flows for the nine months ended September 30, 2008 and 2007. All such adjustments are of a normal recurring nature. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation. The results for interim periods are not necessarily indicative of annual results.

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

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition, see Note D. The operating rights, which have no residual value, are amortized over the estimated economic life of approximately 25 years. Impairment will be assessed when there is a material change in the remaining useful economic life.

Oil and gas sales and imbalances. Oil and natural 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 natural gas sales, recognizing revenues based on the Company s share of actual proceeds from the oil and natural gas sold to purchasers. Oil and natural 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, 2008, the Company had a natural gas imbalance liability, included in asset retirement obligations and other long-term liabilities in the accompanying consolidated balance sheet of approximately $445,000 related to the Company s overtake position of 81,093 Mcf on certain wells and a natural gas imbalance receivable, included in other assets in the accompanying consolidated balance sheet of approximately $373,000 related to the Company s undertake position of 82,990 Mcf on certain wells.

At December 31, 2007, the Company had a natural gas imbalance liability, included in asset retirement obligations and other long-term liabilities in the accompanying consolidated balance sheet, of approximately $621,000 related to the Company s overtake position of 96,215 Mcf on certain wells and a natural gas imbalance receivable, included in other assets in the accompanying consolidated balance sheet, of approximately $367,000 related to the Company s undertake position of 81,569 Mcf on certain wells.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

General and administrative expense. The Company receives fees for its operation of jointly owned oil and gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $2,125,000 and $222,000 for the three months ended September 30, 2008 and 2007, respectively, and $2,629,000 and $852,000 for the nine months ended September 30, 2008 and 2007, respectively.

Note C. *Exploratory well costs*

Costs of drilling exploratory wells are capitalized, pending management s determination of whether the wells have found proved reserves. If proved reserves are found, the costs remain capitalized. If proved reserves are not found, the capitalized costs of drilling the well are charged to expense. Management makes this determination as soon as possible after completion of drilling considering the guidance provided in Financial Accounting Standards Board

(FASB) Statement of Financial Accounting Standards (SFAS) No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* and FASB Staff Position (FSP) No. 19-1, *Accounting for Suspended Well Costs*.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

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

(in thousands)	September 30, 2008	December 31, 2007
Wells in progress	$ 3,446	$ 4,199
Capitalized exploratory well costs that have been capitalized for a period of one year or less	13,061	16,857
Capitalized exploratory well costs that have been capitalized for a period greater than one year		
Total capitalized exploratory well costs	$ 16,507	$ 21,056

At September 30, 2008, the capitalized exploratory well costs of approximately $16.5 million had been deferred for a period of one year or less and were related primarily to the Company s New Mexico shelf properties and emerging resource plays.

Note D. ***Acquisitions***

On July 31, 2008, the Company closed the acquisition of (a) Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (the Henry Entities) and (b) additional non-operated interests in certain Henry Entities oil and gas properties from persons affiliated with the Henry Entities (collectively the 7/31/08 Acquisition). In late August and early September 2008, the Company acquired additional non-operated interests in certain Henry Entities oil and gas properties from persons affiliated with the Henry Entities (which in combination with the 7/31/2008 Acquisition is referred to as the Acquisition or Henry Properties). The Company paid $586.9 million in cash for the Acquisition.

The cash paid for the Acquisition was funded with (a) borrowings under the Company s senior credit facility, see Note K, and (b) proceeds from a private placement of approximately 8.3 million shares of the Company s common stock, see Note H.

The Acquisition is being accounted for using the purchase method of accounting for business combinations. Under the purchase method of accounting, the Company recorded the Henry Properties assets and liabilities at fair value. The purchase price of the acquired Henry Properties net assets will be based on the total value of the cash consideration. The initial purchase price allocation is preliminary and subject to adjustment. Any future adjustments to the allocation of the total purchase price are not anticipated to be material to the Company s consolidated financial statements.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

The following tables represent the preliminary allocation of the total purchase price of the Henry Properties to the acquired assets and liabilities of the Henry Properties and the consideration paid for the Henry Properties. The allocation represents the fair values assigned to each of the assets acquired and liabilities assumed:

(in thousands)	
Fair value of Henry Properties net assets:	
Current assets, excluding cash acquired of $18,960	$ 95,085
Proved oil and gas properties	590,850
Unproved oil and gas properties	220,350
Other long-term assets	7,820
Intangible assets operating rights	48,849
Total assets acquired	962,954
Current liabilities	(129,369)
Asset retirement obligations and other long-term liabilities	(6,837)
Noncurrent derivative liabilities	(39,037)
Deferred tax liability	(200,786)
Total liabilities assumed	(376,029)
Total purchase price	$ 586,925
Consideration paid for Henry Properties net assets:	
Cash consideration paid, excluding cash acquired of $18,960	$ 581,275
Acquisition costs	5,650
Total purchase price	$ 586,925

Estimated acquisition costs include legal and accounting fees, advisory fees and other acquisition-related costs.

8

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

The following unaudited pro forma combined condensed financial data for the nine months ended September 30, 2008 and 2007 was derived from the historical financial statements of the Company and Henry Properties giving effect to the acquisition as if it had occurred on January 1, 2007. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Acquisition taken place as of the dates indicated and is not intended to be a projection of future results.

	Nine Months Ended September 30,	
(in thousands, except per share data)	**2008**	**2007**
Operating revenues	$509,976	$290,972
Net income (loss) applicable to common shareholders	$134,959	$ (6,124)
Earnings (loss) per common share:		
Basic	$ 1.57	$ (0.09)
Diluted	$ 1.55	$ (0.09)

Note E. *Fair value measurements*

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

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

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

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

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

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

	Fair value measurements using			
(in thousands)	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total carrying value at September 30, 2008
Commodity derivative swap contracts	$	$ (34,200)	$	$ (34,200)
Commodity derivative collar contracts			15,419	15,419
Total financial assets (liabilities)	$	$ (34,200)	$ 15,419	$ (18,781)

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

(in thousands)	
Balance as of January 1, 2008	$ 1,866
Gains (losses), realized or unrealized	12,185
Purchases, issuances, and settlements	1,368
Balance as of September 30, 2008	$ 15,419
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets (liabilities) still held at the reporting date	$ 13,553

Note F. ***New accounting pronouncements***

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

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

In June 2007, the FASB ratified a consensus opinion reached by the Emerging Issues Task Force (EITF) on EITF Issue 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards*. EITF Issue 06-11 requires an employer to recognize tax benefits realized from dividend or dividend equivalents paid to employees for certain share-based payment awards as an

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

increase to additional paid-in capital and include such amounts in the pool of excess tax benefits available to absorb future tax deficiencies on share-based payment awards. If an entity s estimate of forfeitures increases (or actual forfeitures exceed the entity s estimates), or if an award is no longer expected to vest, entities should reclassify the dividends or dividend equivalents paid on that award from retained earnings to compensation cost. However, the tax benefits from dividends that are reclassified from additional paid-in capital to the income statement are limited to the entity s pool of excess tax benefits available to absorb tax deficiencies on the date of reclassification. The adoption of EITF Issue 06-11 has not had a significant effect on the Company s financial statements since it historically has accounted for the income tax benefits of dividends paid for share-based payment awards in the manner described in the consensus.

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

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

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

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

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. FSP EITF 03-6-1 is effective for us on January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) will be adjusted retroactively to conform to its provisions. Early application of FSP EITF 03-6-1 is not permitted. Although restricted stock awards meet this definition, the Company does not expect the application of FSP EITF 03-6-1 to have a significant impact on its reported earnings per share.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the united

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

States of America. This statement is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*. The Company does not expect the adoption of SFAS No. 162 to have an impact on its financial statements.

In October 2008, the FASB issued FASB Staff Position (FSP) No. SFAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active*. FSP No. SFAS 157-3 clarifies the application of SFAS No. 157 as it relates to the valuation of financial assets in a market that is not active for those financial assets. This FSP is effective immediately and includes those periods for which financial statements have not been issued. The Company currently does not have any financial assets that are valued using inactive markets, and as a result, the Company is not impacted by the issuance of FSP No. SFAS 157-3.

Note G. *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, 2008 and 2007:

	Nine Months Ended September 30,	
(in thousands)	**2008**	**2007**
Asset retirement obligations, beginning of period	$ 9,418	$ 8,700
Liabilities incurred from new wells	660	309
Liabilities assumed in acquisitions	7,062	
Accretion expense	571	334
Liabilities settled upon plugging and abandoning wells		(34)
Revision of estimates	350	(2,032)
Asset retirement obligations, end of period	$ 18,061	$ 7,277

Note H. *Stockholders equity*

Common stock private placement. On June 5, 2008, the Company entered into a common stock purchase agreement with certain unaffiliated third-party investors to sell certain shares of the Company s common stock in a private placement (the Private Placement) contemporaneous with the closing of the Acquisition. On July 31, 2008, the Company issued 8,302,894 shares of its common stock at $30.11 per share. The Private Placement resulted in net proceeds of approximately $242.4 million to the Company, after payment of approximately $7.6 million for the fee paid to the placement agent.

In connection with the Private Placement, the Company entered into a registration rights agreement with the investors. On October 24, 2008, pursuant to the registration rights agreement, the Company filed a registration statement to register the shares of common stock issued in the Private Placement.

Treasury stock. On June 12, 2008, the restrictions on certain restricted stock awards issued to five of the Company s executive officers lapsed. Immediately upon the lapse of restrictions, these executive officers became liable for certain federal income taxes on the value of such shares. In accordance with the Company s 2006 Stock Incentive

Plan and the applicable restricted stock award agreements, four of such officers elected to deliver shares of the Company s common stock to the Company to satisfy such tax liability, and the Company acquired 3,142 shares to be held as treasury stock in the approximate amount of $125,000.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

Equity commitments. Pursuant to a stock purchase agreement (the Stock Purchase Agreement) entered into on August 13, 2004, CEHC 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 approximately $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 CEHC, the Private Investors and the Officers, certain employees and other officers of the Company entered into separate subscription agreements with the Company. The officers and employees equity purchases were paid for 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 Company s officers and certain employees subject to the 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 CEHC through February 23, 2006, the Private Investors purchased 16,113,170 Preferred Units for $161.1 million in cash; the Company s officers 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, and 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 issuance of preferred stock as a part of the Preferred Units. There were no dividend payments made during the three and nine months ended September 30, 2008, because there was no outstanding preferred stock. Preferred stock dividends of approximately $132,000 were paid during the nine months ended September 30, 2007. As discussed in Note A and below, the majority of the CEHC preferred stock was converted into Resources common stock in the Combination.

Dividend payments continued to be made through April 16, 2007 to the eighteen employee shareholders that did not convert their shares of CEHC preferred stock to Resources common stock in the Combination. 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 date of the Combination.

Purchase notes. On April 23, 2007, the Company s officers repaid their Purchase Notes in full, including principal of $9,426,000 and accrued interest of $1,037,000 in the aggregate. 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 in Note O) the officers held as well as the Capital Options (as defined in Note O) of one certain employee who was formerly an executive officer.

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

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

The following table summarizes the Capital Options activity for the nine months ended September 30, 2008:

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

Conversion of CEHC 6% Series A Preferred Stock and CEHC common stock. On February 27, 2006, concurrent with the closing of the Combination described in Note A, the majority of the shares outstanding of CEHC preferred stock and outstanding shares of CEHC common stock were converted to shares of the Company s 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 the Company s 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 date of the Combination. 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 and the conversion of CEHC preferred stock into the Company s common stock at the ratio of 0.75:1, the CEHC Bundled Capital Options were converted into the Company s Bundled Capital Options and CEHC Capital Options were converted into the Company s Capital Options. The Company s Capital Options are considered to be exercisable for 1.25 shares of the Company s common stock.

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

	Number of restricted shares	Grant date fair value per share
Restricted stock:		

Outstanding at December 31, 2007	371,549		
Shares granted	98,001	$	34.78
Shares cancelled / forfeited	(42,791)		
Lapse of restrictions	(42,001)		
Outstanding at September 30, 2008	384,758		

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

A summary of the impact on the consolidated statements of operations for the Company s restricted stock awards during the three and nine months ended September 30, 2008 and 2007 is presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2008**	**2007**	**2008**	**2007**
Stock-based compensation expense related to restricted stock	$ 716	$ 226	$ 1,578	$ 1,007
Income tax benefit related to restricted stock	$ 276	$ 95	$ 617	$ 422
Deductions in current taxable income related to restricted stock	$ 68	$ 140	$ 1,088	$ 565

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

Risk-free interest rate	3.19%
Expected term (years)	6.21
Expected volatility	38.25%
Expected dividend yield	

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

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

A summary of the Company s stock option awards under the Plan for the nine months ended September 30, 2008 is presented below:

	Number of options	Weighted average exercise price
Stock options:		
Outstanding at December 31, 2007	3,011,722	$ 9.71
Options granted	594,055	$23.57
Options forfeited	(275,593)	$14.96
Options exercised	(430,351)	$ 8.98
Outstanding at September 30, 2008	2,899,833	$12.16
Vested at September 30, 2008	1,749,398	$ 9.10
Exercisable at September 30, 2008	668,957	$10.55

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

		Number vested and exercisable	Weighted average remaining contractual life	Weighted average exercise price	Intrinsic value at September 30, 2008 (in thousands)
Vested options:					
Exercise price	$ 8.00	1,397,198	2.53 years	$ 8.00	$ 27,399
Exercise price	$ 12.00	160,950	4.68 years	$ 12.00	2,512
Exercise price	$ 14.68	191,250	8.03 years	$ 14.68	2,472
		1,749,398		$ 9.10	$ 32,383

Exercisable options:

Exercise price	$ 8.00	370,778	3.83 years	$ 8.00	$ 7,271
Exercise price	$ 12.00	106,929	5.90 years	$ 12.00	1,669
Exercise price	$ 14.68	191,250	8.03 years	$ 14.68	2,472
		668,957		$ 10.55	$ 11,412

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

The following table summarizes information about stock-based compensation for stock options for the three and nine months ended September 30, 2008 and 2007:

(in thousands)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Grant date fair value for awards during the period:				
Time vesting options [a]	$ 206	$ 87	$ 389	$ 87
Officer stock options [c]	585	1,156	5,675	1,156
Total	$ 791	$ 1,243	$ 6,064	$ 1,243
Stock-based compensation expense from stock options:				
Time vesting options [a]	$ 48	$ 6	$ 113	$ 6
Performance vesting options:				
Officers [b]	138	141	402	420
Certain employee [b]	11	10	31	30
Officer stock options [c]	1,012	319	2,830	1,193
Total	$ 1,209	$ 476	$ 3,376	$ 1,649
Income taxes and other information:				
Income tax benefit related to stock options	$ 461	$ 200	$ 1,319	$ 691
Deductions in current taxable income related to stock options exercised	$ 2,880	$	$ 8,218	$
Number of stock options exercised	167		430	

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

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

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

Future stock-based compensation expense. Future stock-based compensation expense at September 30, 2008 is summarized in the table below:

(in thousands)	**Restricted stock**	**Stock options**	**Total**
Remaining 2008	$ 768	$ 1,236	$ 2,004
2009	2,228	2,936	5,164
2010	1,272	1,328	2,600
2011	391	486	877
2012		51	51
Total	$ 4,659	$ 6,037	$ 10,696

Note J. *Derivative financial instruments*

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, (b) support the Company s annual capital budget and expenditure plans and (c) support the economics associated with acquisitions.

Currently, the Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects the changes in the fair value of its derivative instruments in the statements of operations.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

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

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

Therefore, June 30, 2007, was considered the last date the Company s natural gas hedges were highly effective, and the Company discontinued hedge accounting during the three months ended September 30, 2007 and all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges are recorded each period to earnings. Effective portions of dedesignated hedges, previously recorded in accumulated other comprehensive income (AOCI) as of June 30, 2007, remain in AOCI and are being reclassified into earnings under natural gas revenues, during the periods which the hedged forecasted transaction affects earnings.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

Commodity derivative contracts not designated as hedges. During the nine months ended September 30, 2008, the Company entered into additional commodity derivative contracts to hedge a portion of its estimated future production. The following table summarizes information about these additional commodity derivative contracts at September 30, 2008:

	Aggregate remaining volume	Daily volume	Index price	Remaining contract period	
Crude oil (volumes in Bbls):					
Price collar	768,000	2,104	$120.00-$134.60(a)	1/1/09	12/31/09
Price swap	128,800	1,400	$ 99.25(a)	10/1/08	12/31/08
Price swap	147,000	1,598	$124.35(a)	10/1/08	12/31/08
Price swap	292,000	800	$ 98.35(a)	1/1/09	12/31/09
Price swap	348,000	953	$125.10(a)	1/1/09	12/31/09
Price swap	240,000	658	$128.80(a)	1/1/10	12/31/10
Price swap	336,000	921	$128.66(a)	1/1/11	12/31/11
Price swap	504,000	1,377	$127.80(a)	1/1/12	12/31/12
Natural gas (volumes in MMBtus):					
Price swap	1,825,000	5,000	$ 8.44(b)	1/1/09	12/31/09

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

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

Commodity derivative contracts assumed in the Acquisition. As part of the Acquisition, the Company assumed the following commodity derivative contracts at September 30, 2008:

	Aggregate remaining volume	Daily volume	Index price	Remaining contract period

Crude oil (volumes in Bbls):				
Price swap	125,873	1,368	$74.85(a)	10/1/08 - 12/31/08
Price swap	443,491	1,215	$73.59(a)	1/1/09 - 12/31/09
Price swap	401,746	1,101	$72.03(a)	1/1/10 - 12/31/10
Price swap	221,746	608	$68.92(a)	1/1/11 - 12/31/11

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

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

Fair value and activity of commodity derivative contracts. The following table sets forth the Company s outstanding commodity derivative contracts at September 30, 2008:

	Fair value asset (liability) (in thousands)	Aggregate remaining volume	Daily volume	Index price	Remaining contract period
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	$ (7,844)	239,200	2,600	$ 67.50 (a)	10/1/08 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	1,065	1,242,000	13,500	$6.50 $9.35 (b)	10/1/08 12/31/08
Derivatives not designated as hedges:					
Crude oil (volumes in Bbls):					
Price collar	14,354	768,000	2,104	$ 120.00 $134.60 (a)	1/1/09 12/31/09
Price swap	(3,753)	585,673	6,366	$ 92.93 (a) (c)	10/1/08 12/31/08
Price swap	(27,465)	1,813,491	4,968	$ 87.16 (a) (c)	1/1/09 12/31/09
Price swap	(6,654)	641,746	1,758	$ 93.26 (a) (c)	1/1/10 12/31/10
Price swap	(102)	557,746	1,528	$104.91 (a) (c)	1/1/11 12/31/11
Price swap	9,217	504,000	1,377	$127.80 (a)	1/1/12 12/31/12
Natural gas (volumes in MMBtus):					
Price swap	2,401	1,825,000	5,000	$ 8.44 (b)	1/1/09 12/31/09
Net liability	$ (18,781)				

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

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

(c) Prices represent weighted average prices.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

The Company s reported oil and gas revenue includes the effects of crude 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 derivative contracts and the net change in AOCI:

(in thousands)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Increase (decrease) in oil and gas revenue from derivative activity:				
Cash (payments) receipts on cash flow hedges in oil sales	$ (12,111)	$ (3,591)	$ (32,684)	$ (3,347)
Cash receipts from cash flow hedges in gas sales				187
Dedesignated cash flow hedges reclassified from AOCI in gas sales	(38)	722	(260)	722
Total increase (decrease) in oil and gas revenue from derivative activity	$ (12,149)	$ (2,869)	$ (32,944)	$ (2,438)
Gain on derivatives not designated as hedges:				
Mark-to-market gain	$ 176,095	$ 1,802	$ 72,848	$ 1,802
Cash (payments) receipts on derivatives not designated as hedges	(12,783)	1,286	(29,170)	1,286
Total gain on derivatives not designated as hedges	$ 163,312	$ 3,088	$ 43,678	$ 3,088
Gain (loss) from ineffective portion of cash flow hedges:	$ 416	$ 22	$ 1,336	$ (1,134)
Accumulated other comprehensive income (loss):				
Cash flow hedges:				
Mark-to-market gain (loss) of cash flow hedges	$ 14,588	$ (6,843)	$ (17,922)	$ (14,300)
Reclassification adjustment of losses to earnings	12,111	3,591	32,684	3,160
Net AOCI upon dedesignation at June 30, 2007		(407)		(407)
Net change, before income taxes	26,699	(3,659)	14,762	(11,547)
Income tax effect	(10,441)	1,534	(5,776)	4,822
Net change, net of income taxes	$ 16,258	$ (2,125)	$ 8,986	$ (6,725)

Dedesignated cash flow hedges:								
Net AOCI upon dedesignation at June 30, 2007	$		$	407	$		$	407
Reclassification adjustment of (gains) losses to earnings		38		(722)		260		(722)
Income tax effect		(15)		133		(102)		133
Net change, net of income taxes	$	23	$	(182)	$	158	$	(182)

All of the Company s commodity derivative contracts are expected to settle by December 31, 2012. Based on futures prices at September 30, 2008, the Company expects a pre-tax loss of approximately $7.9 million to be reclassified into earnings and a pre-tax loss of approximately $0.4 million to be reclassified out of AOCI into earnings during the three months ended December 31, 2008 related to the cash flow hedges and the dedesignated cash flow hedges, respectively. All the Company s commodity derivative contracts accounted for as cash flow hedges will settle by December 31, 2008.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

Note K. ***Debt***

The Company s debt consisted of the following:

(in thousands)	September 30, 2008	December 31, 2007
Senior Credit Facility	$ 635,000	$ 216,000
2nd Lien Credit Facility		109,900
Unamortized original issue discount on 2nd Lien Credit Facility		(496)
Total long-term debt	635,000	325,404
Current portion of 2nd Lien Credit Facility		2,000
Total debt	$ 635,000	$ 327,404

Senior credit facility. On July 31, 2008, the Company amended and restated its senior credit facility in various respects, including increasing the borrowing base to $960 million, subject to scheduled semiannual redeterminations, and extending the maturity date to July 31, 2013 (the Senior Credit Facility). The Company paid an arrangement fee of $14.4 million upon closing the Senior Credit Facility. At September 30, 2008, the Company had letters of credit outstanding under the Senior Credit Facility of approximately $275,000 and its availability to borrow additional funds was $324.7 million. In October 2008, the Company s $960 million borrowing base was reaffirmed until the next scheduled borrowing base redetermination in 2009. Between scheduled borrowing base redeterminations the Company and, if requested by 66 2/3 percent of the lenders, the lenders may each request one special redetermination.

Advances on the Senior Credit Facility bear interest, at the Company s option, based on (a) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (5.00 percent at September 30, 2008) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 125 to 275 basis points and zero to 125 basis points, respectively, per annum depending on the balance outstanding. The Company pays commitment fees on the unused portion of the available borrowing base ranging from 25 to 50 basis points per annum.

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

The Company s obligations under the Senior Credit Facility are secured by a first lien on substantially all of the Company s oil and gas properties. In addition, all of the Company s subsidiaries are guarantors and all general partner, limited partner and membership interests in the Company s subsidiaries owned by the Company have been pledged to secure borrowings under the Senior Credit Facility. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios 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 noncash income and expenses to be greater than 4.0 to 1.0, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations and including the unfunded amounts under the Senior Credit Facility, to be no less than 1.0 to 1.0; (b) limits on the incurrence of additional indebtedness and certain types of liens; (c) restrictions as to mergers and sales or transfer of assets; and (d) a restriction on the payment of cash dividends.

2nd lien credit facility. On March 27, 2007, the Company entered into a second lien credit facility (the 2nd Lien Credit Facility), for a term loan facility in the amount of $200 million. The 2nd Lien Credit Facility was fully paid on July 31, 2008 from proceeds from the Company s Senior Credit Facility and the facility was terminated.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

Principal maturities of debt. Principal maturities of debt outstanding at September 30, 2008 are as follows:

(in thousands)	
2008	$
2009	
2010	
2011	
2012 and thereafter	635,000
Total	$ 635,000

Interest expense. The following amounts have been incurred and charged to interest expense for the three and nine months ended September 30, 2008 and 2007:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2008	2007	2008	2007
Cash payments for interest	$ 6,496	$ 15,485	$ 17,254	$ 34,482
Amortization of original issue discount	8	34	58	74
Amortization of deferred loan origination costs	674	338	1,300	1,026
Write-off of deferred loan origination costs and original issue discount	1,547	1,430	1,547	2,631
Net changes in accruals	1,780	(7,079)	686	(6,250)
Interest costs incurred	10,505	10,208	20,845	31,963
Less: capitalized interest	(250)	(1,154)	(1,090)	(2,160)
Total interest expense	$ 10,255	$ 9,054	$ 19,755	$ 29,803

Note L. *Commitments and contingencies*

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company s officers covered under such agreements total approximately $1.9 million.

Indemnifications. The Company has agreed to indemnify its directors and officers, employees and agents with respect to claims and damages arising from acts or omissions taken in such capacity, as well as with respect to certain litigation.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to such proceedings and claims will not have a material adverse effect on the Company s consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company will continue to evaluate litigation against the Company on a quarter-by-quarter basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Acquisition commitments. In connection with the Acquisition, the Company agreed to pay certain employees of the Henry Entities bonuses of approximately $11.0 million in the aggregate at each of the first and second anniversaries of the closing of the Acquisition, respectively. Except as described below, these employees must remain employed with the Company to receive the bonus. A Henry Entities employee who is otherwise entitled to a full bonus will receive the full bonus (a) if the Company terminates the employee without cause, (b) upon death or disability of such employee or (c) upon a change in control of the Company. If such employee resigns or is terminated for cause the employee will not receive the bonus and the Company will be required to pay the sellers in the Acquisition 65 percent of the bonus amount not paid to the employee. The Company will reflect the bonus amounts to be paid to these employees as a period cost which will be included in the Company s results of operations over the period earned. Amounts that

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

ultimately are determined to be paid to the sellers will be treated as a contingent purchase price and reflected as an adjustment to the purchase price.

***Drilling commitments*.** The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is incurred or rig services are provided. The following table summarizes the Company s future drilling commitments at September 30, 2008:

		Payments due by period			
(in thousands)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Daywork drilling contracts	$ 8,104	$ 8,104	$	$	$
Daywork drilling contracts with related parties [(a)]	17,632	17,632			
Daywork drilling contracts assumed in the Acquisition [(b)]	8,143	5,361	2,782		
Total contractual drilling commitments	$ 33,879	$ 31,097	$ 2,782	$	$

(a) Consists of daywork drilling contracts with Silver Oak Drilling, LLC, an affiliate of the Chase Group.

(b) A major oil and gas company which owns an interest in the wells being drilled and the Company are parties to these contracts. Only the Company s 25% share of the contract obligation has been reflected above.

Note M. ***Income taxes***

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

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

The FASB issued FIN No. 48-1, *Definition of Settlement in FASB Interpretation No. 48*, (FIN No. 48-1) to clarify when a tax position is effectively settled. FIN No. 48-1 provides guidance in determining the proper timing for recognizing tax benefits and applying the new information relevant to the technical merits of a tax position obtained during a tax authority examination. FIN No. 48-1 provides criteria to determine whether a tax position is effectively settled after completion of a tax authority examination, even if the potential legal obligation remains under the statute of limitations. The Company s adoption of this pronouncement did not have a significant effect on its consolidated financial statements.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

Income tax provision. The Company s income tax provision consisted of the following for the three and nine months ended September 30, 2008 and 2007:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2008**	**2007**	**2008**	**2007**
Current:				
U.S. federal	$ 7,620	$ 1,578	$ 8,234	$ 1,549
U.S. state and local	1,007	333	1,088	326
	8,627	1,911	9,322	1,875
Deferred:				
U.S. federal	73,865	3,282	77,902	9,262
U.S. state and local	8,539	779	9,006	2,198
	82,404	4,061	86,908	11,460
	$ 91,031	$ 5,972	$ 96,230	$ 13,335

The reconciliation between the tax expense computed by multiplying pretax income by the U.S. federal statutory rate and the reported amounts of income tax expense is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2008**	**2007**	**2008**	**2007**
Income at U.S. federal statutory rate	$ 81,536	$ 4,874	$ 86,136	$ 11,143
State income taxes (net of federal tax effect)	9,546	1,112	10,094	2,525
Nondeductible expense & other	(51)	(14)		(333)
Expense for income taxes	$ 91,031	$ 5,972	$ 96,230	$ 13,335

Note N. *Related parties*

Contract Operator Agreement and Transition Services Agreement. On February 27, 2006, the Company signed a Contract Operator Agreement with Mack Energy Corporation (MEC), an affiliate of the Chase Group, whereby the Company engaged MEC as its contract operator to provide certain services with respect to the Chase Group Properties. The initial term of the Contract Operator Agreement was five years commencing on March 1, 2006 and ending on February 28, 2011. The Company and MEC entered into a Transition Services Agreement on April 23, 2007, which terminated the Contract Operator Agreement and under which MEC continued to provide certain field level operating services on the Chase Group Properties. The Transition Services Agreement was terminated automatically on August 7, 2007 upon the Company s completion of the IPO. Upon termination of such agreement, 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 million 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 $184,000 and $1.7 million for the three and nine months ended September 30, 2008, respectively, in the ordinary course of business.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

The Company had outstanding invoices payable to MEC of approximately $0.4 million at December 31, 2007, which are reflected in accounts payable related parties in the accompanying consolidated balance sheet. The Company had no outstanding invoices payable to MEC at September 30, 2008.

Other related party transactions. The Company also has engaged in transactions with certain other affiliates of the Chase Group, including a drilling contractor, 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 $6.5 million and $19.6 million for the three and nine months ended September 30, 2008, respectively, for services rendered and charges 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 had outstanding invoices payable to the other related party vendors identified above of approximately $148,000 and $1.7 million at September 30, 2008 and December 31, 2007, respectively, which are reflected in accounts payable related parties in the accompanying consolidated balance sheets.

Overriding royalty and royalty interests. Certain members of the Chase Group own overriding royalty interests in certain of the Chase Group Properties. The amount paid attributable to such interests was approximately $984,000 and $2.6 million for the three and nine months ended September 30, 2008, respectively. The amount paid attributable to such interests was approximately $672,000 and $1.6 million for the three and nine months ended September 30, 2007, respectively. The Company owed these owners royalty payments of approximately $290,000 and $315,000 at September 30, 2008 and December 31, 2007, respectively.

Royalties are paid on certain properties located in Andrews County, Texas to a partnership of which one of the Company s directors is the general partner, and who also owns a 3.5% partnership interest. The Company paid this partnership approximately $115,000 and $279,000 for the three and nine months ended September 30, 2008, respectively. The Company paid this partnership approximately $50,000 and $109,000 for the three and nine months ended September 30, 2007, respectively. The Company owed this partnership royalty payments of approximately $29,000 at September 30, 2008 and December 31, 2007.

In April 2005, the Company acquired certain working interests in 46,861 gross (26,908 net) acres located in Culberson County, Texas from an entity partially owned by a person who became an executive officer of the Company immediately following such acquisition. In connection with this acquisition, such entity retained a 2% overriding royalty interest in the acquired properties, which overriding royalty interest later became owned equally by such officer and a non-officer employee of the Company. During the three and nine months ended September 30, 2008, no payments were made related to this overriding royalty interest. The overriding royalty interest amount attributable to such interest was approximately $1,000 and $3,000 during the three and nine months ended September 30, 2007, respectively. Effective March 31, 2008, the executive officer involved in this matter resigned from the Company.

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

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

At September 30, 2008 and December 31, 2007, the Company had no amounts due Caza.

Note O. *Net income per share*

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

The computation of diluted income per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income were exercised or converted into common stock or resulted in the issuance of common stock

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

that would then share in the earnings of the Company. These amounts include unexercised Bundled Capital Options, Capital Options, stock options and restricted stock (as issued under the Plan and described in Note I). Potentially dilutive effects are calculated using the treasury stock method.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2008**	**2007**	**2008**	**2007**
Weighted average common shares outstanding:				
Basic	81,288	69,067	77,489	60,648
Dilutive Bundled Capital Options				1,130
Dilutive Capital Options		83	8	163
Dilutive common stock options	1,195	710	1,203	852
Dilutive restrictive stock	241	53	245	65
Diluted	82,724	69,913	78,945	62,858

For the nine months ended September 30, 2008 and the three and nine months ended September 30, 2007, the effects of all potentially dilutive securities, including Bundled Capital Options, Capital Options and stock options were included in the computation of diluted earnings per share because there were no antidilutive effects.

Options equivalent to 96,555 shares of common stock were not included in the computation of diluted income per share for the three months ended September 30, 2008, respectively, as inclusion of these items would be antidilutive.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
Unaudited

Note P. ***Supplementary information***
Capitalized costs

(in thousands)	September 30, 2008	December 31, 2007
Oil and gas properties:		
Proved	$ 2,135,089	$ 1,303,665
Unproved	445,419	251,353
Less: accumulated depletion	(244,175)	(167,109)
Net capitalized costs for oil and gas properties	$ 2,336,333	$ 1,387,909

Costs incurred for oil and gas producing activities

(in thousands)	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Property acquisition costs:				
Proved	$ 589,986(a)	$ 3,801	$ 589,987(a)	$ 11,801
Unproved	223,892	1,857	225,241	(2,239)
Exploration	30,131	29,239	80,638	70,973
Development	78,104	26,880	148,903	44,253
Capitalized asset retirement obligations	373	(662)	1,010	(1,951)
Total costs incurred for oil and gas properties	$ 922,486	$ 61,115	$ 1,045,779	$ 122,837

(a) Includes approximately $7.1 million of asset retirement obligations assumed in the Acquisition.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

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

During the third quarter of 2008, the Company closed a significant acquisition as discussed below. As a result of the acquisition many comparisons between periods will be difficult or impossible.

Statements in this 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. See Cautionary statement regarding forward-looking statements.

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of producing oil and natural gas properties. Our conventional operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We have also acquired significant acreage positions in unconventional emerging resource plays located in the Permian Basin of Southeast New Mexico, the Central Basin Platform and the Western Delaware Basin of West Texas, the Williston Basin in North Dakota and the Arkoma Basin in Arkansas, where we intend to apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies. On a pro forma basis for the Acquisition, as defined below, crude oil comprised 61% of our 692.3 Bcfe of estimated net proved reserves at December 31, 2007, and 63% of our 38.9 Bcfe of production for the year ended December 31, 2007. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 91% of our PV-10, on a pro forma basis, at December 31, 2007. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Commodity prices

Factors that may impact future commodity prices, including the price of oil and natural gas, include developments generally impacting the Middle East and Iraq and Iran specifically; the extent to which members of the OPEC and other oil exporting nations are able to continue to manage oil supply through export quotas; and overall North American gas supply and demand fundamentals, including the impact of the decline of the U.S. economy, weather conditions and LNG deliveries to the United States. Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note I of Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information regarding our commodity hedge positions at September 30, 2008.

The average NYMEX crude oil price for the three months ended September 30, 2008 was $118.52. The NYMEX crude oil price at October 31, 2008 was $67.81. The average NYMEX natural gas price for the three months ended September 30, 2008 was $9.02. The NYMEX natural gas price at October 31, 2008 was $6.78.

Recent events

Henry Petroleum acquisition. On July 31, 2008, we closed the acquisition of (a) Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (the Henry Entities) and (b) additional non-operated interests in certain Henry Entities oil and gas properties from persons affiliated with the Henry Entities (collectively the 7/31/08 Acquisition). In late August and early September 2008, we acquired additional non-operated interests in certain Henry Entities oil and gas properties from persons affiliated with the Henry Entities (which in combination with the 7/31/2008 Acquisition is referred to as the Acquisition or Henry Properties). We paid $586.9 million in cash for the Acquisition. The Acquisition was funded with (a) borrowings under our senior credit facility and (b) proceeds from a private placement of approximately 8.3 million shares of our common stock.

Amended and restated credit facility. On July 31, 2008, the Company amended and restated its senior credit facility in various respects, including increasing the borrowing base to $960 million, subject to scheduled semiannual redeterminations, and extending the maturity date from February 24, 2011 to July 31, 2013 (the Senior Credit Facility). The initial borrowing under the Senior Credit Facility was $675 million. We paid an arrangement fee of $14.4 million upon closing the Senior Credit Facility. On July 31, 2008, we repaid all amounts outstanding under our 2nd lien credit facility and terminated the facility. In October 2008, our $960 million borrowing base was reaffirmed until the next scheduled borrowing base redetermination in 2009. Between scheduled borrowing base redeterminations we and, if requested by 66 2/3 percent of the lenders, the lenders may each request one special redetermination.

Common stock private placement. On July 31, 2008, we closed a private placement of 8.3 million shares of our common stock at $30.11 per share. The private placement resulted in net proceeds of approximately $242.4 million for us, after payment of approximately $7.6 million for the fee paid the placement agent.

2009 capital budget. On November 6, 2008, our board of directors approved a capital budget for 2009 of up to approximately $500 million. The capital budget is predicated on us funding it substantially within our cash flow. If commodity prices continue their decline, and considering other factors that may change, we expect we would curtail our spending such that we spend substantially within our cash flow. The following is a summary of our 2009 capital budget:

(in millions)	**2009 Budget**
Drilling and recompletion opportunities in our core operating area	$ 398
Projects operated by third parties	8
Emerging plays, acquisition of leasehold acreage and other property interests, and geological and geophysical	72
Maintenance capital in our core operating areas	22
Total 2009 capital budget	$ 500

Short-term interruptions in production. During 2008, our production has been interrupted on several occasions. The following represent the significant interruptions:

None of our properties and facilities were directly impacted by Hurricane Ike; however, facilities which ultimately received our production, primarily natural gas liquids, sustained power interruptions and physical damage. As a result, our production was either curtailed or shut-in for periods of time. As a result, we estimate that our September 2008 production was reduced by approximately 700 MMcfe and our October 2008 production was reduced by approximately 200 MMcfe.

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

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

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

Derivative financial exposure. At September 30, 2008, the fair value of our financial commodity derivatives was a net liability of $18.8 million. All of our counterparties to these commodity derivatives are part of our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Pursuant to the terms of our commodity derivative instruments and their collateralization under our credit facility, we do not have exposure to potential margin calls on our commodity derivative instruments which could cause us to have a significant liquidity event.

In light of the recent drop in commodity prices, some of our commodity derivative instruments are currently in a net asset position to us. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Currently, all of our counterparties are part of our credit facility, and our credit facility does not allow us to offset amounts we may owe a lender under our credit facility against amounts we may be owed related to our commodity derivative instruments with such party.

Table of Contents

New commodity derivative contracts. During the nine months ended September 30, 2008, we entered into additional commodity derivative contracts to hedge a portion of our estimated future production. The following table summarizes information about these additional commodity derivative contracts at September 30, 2008:

	Aggregate remaining volume	Daily volume	Index price	Remaining contract period	
Crude oil (volumes in Bbls):					
Price collar	768,000	2,104	$120.00-$134.60(a)	1/1/09	12/31/09
Price swap	128,800	1,400	$ 99.25(a)	10/1/08	12/31/08
Price swap	147,000	1,598	$124.35(a)	10/1/08	12/31/08
Price swap	292,000	800	$ 98.35(a)	1/1/09	12/31/09
Price swap	348,000	953	$125.10(a)	1/1/09	12/31/09
Price swap	240,000	658	$128.80(a)	1/1/10	12/31/10
Price swap	336,000	921	$128.66(a)	1/1/11	12/31/11
Price swap	504,000	1,377	$127.80(a)	1/1/12	12/31/12
Natural gas (volumes in MMBtus):					
Price swap	1,825,000	5,000	$ 8.44(b)	1/1/09	12/31/09

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

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

Commodity derivative contracts assumed in the Acquisition. As part of the Acquisition, we assumed the following commodity derivative contracts at September 30, 2008:

	Aggregate remaining volume	Daily volume	Index price	Remaining contract period	
Crude oil (volumes in Bbls):					
Price swap	125,873	1,368	$74.85(a)	10/1/08	12/31/08
Price swap	443,491	1,215	$73.59(a)	1/1/09	12/31/09

Price swap	401,746	1,101	$72.03(a)	1/1/10	12/31/10
Price swap	221,746	608	$68.92(a)	1/1/11	12/31/11

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

Table of Contents

Results of operations

The following table presents selected financial and operating information for the three and nine months ended September 30, 2008 and 2007:

(in thousands, except price and daily volume data)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Oil sales	$ 130,600	$ 45,685	$ 301,826	$ 128,152
Natural gas sales	39,857	23,413	112,725	67,395
Total operating revenues	170,457	69,098	414,551	195,547
Operating costs and expenses	90,889	49,690	194,036	137,952
Gain on derivatives not designated as hedges	(163,312)	(3,088)	(43,678)	(3,088)
Interest, net and other revenue	9,921	8,570	18,090	28,846
Income before income taxes	232,959	13,926	246,103	31,837
Income tax expense	(91,031)	(5,972)	(96,230)	(13,335)
Net income	$ 141,928	$ 7,954	$ 149,873	$ 18,502
Production volumes:				
Oil (MBbl)	1,247	705	3,033	2,143
Natural gas (MMcf)	3,944	2,982	10,395	8,887
Natural gas equivalent (MMcfe)	11,426	7,211	28,593	21,747
Average daily production volumes:				
Oil (Bbl)	13,554	7,663	11,069	7,850
Natural gas (Mcf)	42,870	32,413	37,938	32,553
Natural gas equivalent (Mcfe)	124,196	78,380	104,354	79,659
Average prices:				
Oil, without hedges (Bbl)	$ 114.44	$ 69.91	$ 110.29	$ 61.36
Oil, with hedges (Bbl)	$ 104.73	$ 64.82	$ 99.51	$ 59.79
Natural gas, without hedges (Mcf)	$ 10.12	$ 7.61	$ 10.87	$ 7.48
Natural gas, with hedges (Mcf)	$ 10.11	$ 7.85	$ 10.84	$ 7.58
Natural gas equivalent, without hedges (Mcfe)	$ 15.98	$ 9.98	$ 15.65	$ 9.10
Natural gas equivalent, with hedges (Mcfe)	$ 14.92	$ 9.58	$ 14.50	$ 8.99

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, 2008, compared to three months ended September 30, 2007

Oil and gas revenues. Revenue from oil and gas operations was $170.5 million for the three months ended September 30, 2008, an increase of $101.4 million (147%) from $69.1 million for the three months ended September 30, 2007. This increase was primarily due to the Acquisition on July 31, 2008, increased production due to successful drilling efforts during 2008, and substantial increases in realized oil and gas prices. In addition:

- average realized oil prices (after giving effect to hedging activities) were $104.73 per Bbl during the three months ended September 30, 2008, an increase of 62% from $64.82 per Bbl during the three months ended September 30, 2007;

- total oil production was 1,247 MBbl for the three months ended September 30, 2008, an increase of 542 MBbl (77%) from 705 MBbl for the three months ended September 30, 2007;

- average realized natural gas prices (after giving effect to hedging activities) were $10.11 per Mcf during the three months ended September 30, 2008, an increase of 29% from $7.85 per Mcf during the three months ended September 30, 2007;

- total natural gas production was 3,944 MMcf for the three months ended September 30, 2008, an increase of 962 MMcf (32%) from 2,982 MMcf for the three months ended September 30, 2007;

- average realized natural gas equivalent prices (after giving effect to hedging activities) were $14.92 per Mcfe during the three months ended September 30, 2008, an increase of 56% from $9.58 per Mcfe during the three months ended September 30, 2007; and

- total production was 11,426 MMcfe for the three months ended September 30, 2008, an increase of 4,215 MMcfe (58%) from 7,211 MMcfe for the three months ended September 30, 2007.

See discussion in Recent events about our 2008 production interruptions.

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 in order to (i) reduce the effect of the volatility of price changes on the commodities we produce and sell, (ii) support our annual capital budget and expenditure plans and (iii) lock-in commodity prices to protect economics related to certain capital projects. The following is a summary of the effects of commodity hedges that qualify for hedge accounting treatment for the three months ended September 30, 2008 and 2007:

	Crude Oil Hedges Three Months Ended September 30,		Natural Gas Hedges Three Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Hedging revenue increase (decrease) (in thousands)	$ (12,111)	$ (3,591)	$ (38)	$ 722
Hedged volumes (Bbls and MMBtus, respectively)	239,000	271,400	1,242,000	1,665,200
Hedged revenue increase (decrease) per hedged volume	$ (50.67)	$ (13.23)	$ (0.03)	$ 0.43

During the three months ended September 30, 2008, our commodity price hedges decreased oil revenues by $12.1 million ($9.71 per Bbl). During the three months ended September 30, 2007, our commodity price hedges decreased oil revenues by $3.6 million ($5.09 per Bbl). The effect of the commodity price hedges in decreasing oil revenues during the three months ended September 30, 2008 compared to their effect of decreasing oil revenues during the three months ended September 30, 2007 was the result of (i) a higher average market price of NYMEX crude oil of $118.52 per Bbl in 2008 as compared to $75.21 per Bbl in 2007 and (ii) the greater price difference between NYMEX and the weighted average hedge price in 2008 as compared to 2007, partially offset by a lower amount of hedged volumes of 239,000 Bbls in 2008 as compared to 271,400 Bbls in 2007.

During the three months ended September 30, 2008, our commodity price hedges decreased gas revenues by $38,000 ($0.24 per Mcf) as a result of the amount reclassified from AOCI into natural gas revenues from cash flow hedges that were dedesignated as of June 30, 2007. Cash settlements for these dedesignated natural gas contracts are being recorded as a gain on derivatives not designated as hedges. During the three months ended September 30, 2007, our commodity price hedges increased gas revenues by $0.7 million ($0.24 per Mcf) as a result of the price difference between the market reference price of natural gas and the commodity contract price.

Table of Contents

Production expenses. The following tables provide the components of our total oil and gas production costs for the three months ended September 30, 2008 and 2007:

	Three Months Ended September 30,			
	2008		2007	
(in thousands, except per unit amounts)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**
Lease operating expenses	$ 12,338	$ 1.08	$ 6,839	$ 0.95
Taxes:				
Ad valorem	792	0.07	398	0.06
Production	13,734	1.20	5,673	0.79
Workover costs	177	0.02	863	0.12
Total oil and gas production expenses	$ 27,041	$ 2.37	$ 13,773	$ 1.92

Among the cost components of production expenses, in general, we have management control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $12.3 million ($1.08 per Mcfe) for the three months ended September 30, 2008, an increase of $5.5 million (80%) from $6.8 million ($0.95 per Mcfe) for the three months ended September 30, 2007. The increase in lease operating expenses is due to (i) the wells acquired in the Acquisition, which increased the absolute and per unit amount because those wells have a higher per unit cost as compared to our historical per unit cost, (ii) our new wells successfully drilled and completed in 2008 and (iii) general inflation of field service and supply costs associated with rising commodity prices.

Ad valorem taxes have increased primarily as a result of (i) the Acquisition and (ii) the increase in commodity prices.

Production taxes per unit of production were $1.20 per Mcfe during the three months ended September 30, 2008, an increase of 52% from $0.79 per Mcfe during the three months ended September 30, 2007. The increase is directly tied to the increase in oil and gas revenues and the related increase in commodity prices. Over the same period our natural gas equivalent prices (before the effects of hedging) increased 60%.

Workover expenses were $0.9 million for the three months ended September 30, 2007, due to a workover project on a property located in Gaines County, Texas.

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

	Three Months Ended September 30,	
(in thousands)	**2008**	**2007**
Geological and geophysical	$ 111	$ 368
Exploratory dry holes	2,779	10,557
Leasehold abandonments and other	13,934	880
Total exploration and abandonments	$ 16,824	$ 11,805

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, during the three months ended September 30, 2008 was $0.1 million, a decrease of $0.3 million from $0.4 million for the three months ended September 30, 2007. This decrease is primarily attributable to higher petro-physical data processing expenses during the three months ended September 30, 2007.

Our exploratory dry hole expense during the three months ended September 30, 2008 is primarily attributable to an unsuccessful operated exploratory well located in Eddy County, New Mexico. Our exploratory dry hole expense during the three months ended September 30, 2007 is primarily attributable to two unsuccessful operated exploratory wells. The costs associated with the two wells

Table of Contents

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 related to two unsuccessful outside operated wells in Eddy County, New Mexico.

For the three months ended September 30, 2008, we recorded $13.9 million of leasehold abandonments, which are primarily related to one prospect in Culberson County, Texas and a portion of our Fayetteville acreage in Arkansas. For the three months ended September 30, 2007, we had $0.9 million of leasehold abandonments related to one prospect located in Edwards County, Texas.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the three months ended September 30, 2008 and 2007:

	Three Months Ended September 30,			
	2008		**2007**	
(in thousands, except per unit amounts)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**
Depletion of proved oil and gas properties	$ 31,729	$ 2.78	$ 17,748	$ 2.46
Depreciation of other property and equipment	473	0.04	255	0.04
Amortization of intangible asset operating rights	326	0.03		
Total depletion, depreciation and amortization	$ 32,528	$ 2.85	$ 18,003	$ 2.50
Crude oil price used to estimate proved oil reserves at period end	$ 97.00		$ 78.25	
Natural gas price used to estimate proved gas reserves at period end	$ 7.12		$ 6.38	

Depletion of proved oil and gas properties was $31.7 million ($2.78 per Mcfe) for the three months ended September 30, 2008, an increase of $14.0 million from $17.7 million ($2.46 per Mcfe) for the three months ended September 30, 2007. The increase in depletion expense was primarily due to (i) the Acquisition for which the depletion rate was $3.25 per Mcfe for the three months ended September 30, 2008 and (ii) capitalized costs associated with new wells that were successfully drilled and completed in 2007 and 2008. The increase was partially offset by the increase in the oil and natural gas prices, as noted above, between the periods which were utilized to determine the proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the Acquisition. The intangible asset is currently being amortized over an estimated life of approximately 25 years.

Impairment of long-lived assets. In accordance with SFAS No. 144, we periodically 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, 2008, we recognized a non-cash charge against earnings of $2.8 million, which was comprised primarily of a field in Eddy County, New Mexico. For the three months ended September 30, 2007, we recognized a non-cash charge against earnings of $1.4 million, primarily related to a field in Crane County, Texas.

Table of Contents

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended September 30, 2008 and 2007:

	Three Months Ended September 30,			
	2008		2007	
(in thousands, except per unit amounts)	Amount	Per Mcfe	Amount	Per Mcfe
General and administrative expenses recurring	$ 8,611	$ 0.75	$ 4,166	$ 0.58
Non-recurring bonus paid to Henry Entities employees, see Note L	2,367	0.21		
Non-cash stock-based compensation stock options	1,209	0.11	476	0.07
Non-cash stock-based compensation restricted stock	716	0.06	226	0.03
Less: Third-party operating fee reimbursements	(2,125)	(0.19)	(222)	(0.03)
Total general and administrative expenses	$ 10,778	$ 0.94	$ 4,646	$ 0.65

General and administrative expenses were $10.8 million ($0.94 per Mcfe) for the three months ended September 30, 2008, an increase of $6.1 million (132%) from $4.6 million ($0.65 per Mcfe) for the three months ended September 30, 2007. The increase in general and administrative expenses during the three months ended September 30, 2008 over the three months ended September 30, 2007 was primarily due to (i) the non-recurring bonus paid to Henry Entities employees, (ii) an increase in non-cash stock-based compensation for both stock options and restricted stock awards and (iii) an increase in the number of employees and related personnel expenses, partially offset by an increase in third-party operating fee reimbursements.

As part of the Acquisition, we agreed to pay certain of the Henry Entities employees a predetermined bonus amount, in addition to the compensation we pay these employees, over the next two years. Since these employees will earn this bonus over the next two years we are reflecting the cost in our general and administrative costs. We are reflecting this bonus amount as non-recurring as it is not controlled by our management. See Note L for additional information related to this bonus.

We earn reimbursements as operator of certain oil and gas properties in which we own interests. As such, we earned reimbursements of $2.1 million and $0.2 million during the three months ended September 30, 2008 and 2007, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in this reimbursement is directly related to the Acquisition, as we own a lower working interest in these operated properties compared to our historical operated property base, thus we have a larger third-party reimbursement as compared to our historical property base.

Bad debt expense. On May 20, 2008, we entered into a short-term purchase agreement with an oil purchaser to buy a portion of the oil affected as a result of the New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared bankruptcy. We fully reserved the receivable amount due from this purchaser for July production of approximately $1.1 million during the three months ended September 30, 2008.

Gain on derivatives not designated as hedges. As discussed in Note J, during the three months ended June 30, 2007, we determined that all of our natural gas commodity derivative contracts no longer qualified as hedges under the requirements of SFAS No. 133. If the hedge is no longer highly effective, according to SFAS No. 133, an entity shall discontinue hedge accounting for an existing hedge, prospectively, and during the period the hedges became ineffective. In addition, for our new commodity derivative contracts entered into after August 2007, we chose not to designate any of these contracts as hedges. As a result, any changes in fair value and any cash settlements related to these contracts are recorded in earnings during the related period.

For the three months ended September 30, 2008, the related cash payments for settlements for derivative contracts not designated as hedges was approximately $12.8 million. The non-cash mark-to-market adjustment for the derivative contracts not designated as hedges was a gain of $176.1 million. This is compared to cash receipts for settlements of $1.3 million and non-cash mark-to-market gains of $1.8 million for the three months ended September 30, 2007.

Interest expense. Interest expense was $10.3 million for the three months ended September 30, 2008, an increase of $1.2 million from $9.1 million for the three months ended September 30, 2007. The weighted average interest rate for the three months ended September 30, 2008 and 2007 was 4.2% and 7.8%, respectively. The weighted average debt balance during the three months ended September 30, 2008 and 2007 was approximately $541.4 million and $415.4 million, respectively.

The increase in weighted average debt balance during the three months ended September 30, 2008 was due primarily to borrowings in July 2008 for the Acquisition. The increase in interest expense is due to an increase in the weighted average debt balance offset by a decrease in the weighted average interest rate. In July 2008, we repaid and terminated the 2nd Lien Credit Facility, which resulted in the write-off of approximately $1.1 million of deferred loan costs and approximately $0.4 million of original issue discount, both of which are included in interest expense. In August 2007, we made a $86.6 million partial prepayment on our 2nd Lien Credit Facility from proceeds of our initial public offering, which resulted in the write-off of approximately $1.0 million of deferred loan costs and approximately $0.4 million of original issue discount, both of which are included in interest expense. The decrease in the weighted average interest rate is due to (i) improvement in market interest rates and (ii) the fact that the interest rate margins under the Senior Credit Facility were lower than those under the 2nd Lien Credit Facility.

Income tax provisions. We recorded an income tax expense of $91.0 million and $6.0 million for the three months ended September 30, 2008 and 2007, respectively. The effective income tax rate for the three months ended September 30, 2008 and 2007 was 39.1% and 42.9%, respectively. We estimated a higher effective state income rate in 2007 than in 2008, which is primarily due to our estimate of income among the various states in which we own assets.

Nine months ended September 30, 2008, compared to nine months ended September 30, 2007

Oil and gas revenues. Revenue from oil and gas operations was $414.6 million for the nine months ended September 30, 2008, an increase of $219.0 million (112%) from $195.5 million for the nine months ended September 30, 2007. This increase was primarily due to (i) the Acquisition on July 31, 2008, (ii) increased production due to successful drilling efforts during 2008 and (iii) substantial increases in realized oil and gas prices. In addition:

- average realized oil prices (after giving effect to hedging activities) were $99.51 per Bbl during the nine months ended September 30, 2008, an increase of 66% from $59.79 per Bbl during the nine months ended September 30, 2007;

- total oil production was 3,033 MBbl for the nine months ended September 30, 2008, an increase of 890 MBbl (42%) from 2,143 MBbl for the nine months ended September 30, 2007;

- average realized natural gas prices (after giving effect to hedging activities) were $10.84 per Mcf during the nine months ended September 30, 2008, an increase of 43% from $7.58 per Mcf during the nine months ended September 30, 2007;

- total natural gas production was 10,395 MMcf for the nine months ended September 30, 2008, an increase of 1,508 MMcf (17%) from 8,887 MMcf for the nine months ended September 30, 2007;

- average realized natural gas equivalent prices (after giving effect to hedging activities) were $14.50 per Mcfe during the nine months ended September 30, 2008, an increase of 61% from $8.99 per Mcfe during the nine months ended September 30, 2007; and

- total production was 28,593 MMcfe for the nine months ended September 30, 2008, an increase of 6,846 MMcfe (31%) from 21,747 MMcfe for the nine months ended September 30, 2007.

See discussion in Recent events about our 2008 production interruptions.

Table of Contents

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 in order to (i) reduce the effect of the volatility of price changes on the commodities we produce and sell, (ii) support our annual capital budget and expenditure plans and (iii) lock-in commodity prices to protect economics related to certain capital projects. The following is a summary of the effects of commodity hedges that qualify for hedge accounting treatment for the nine months ended September 30, 2008 and 2007:

	Crude Oil Hedges Nine Months Ended September 30,		Natural Gas Hedges Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Hedging revenue increase (decrease) (in thousands)	$ (32,684)	$ (3,347)	$ (260)	$ 909
Hedged volumes (Bbls and MMBtus, respectively)	712,000	805,350	3,699,000	4,817,000
Hedged revenue increase (decrease) per hedged volume	$ (45.90)	$ (4.16)	$ (0.07)	$ 0.19

During the nine months ended September 30, 2008, our commodity price hedges decreased oil revenues by $32.7 million ($10.78 per Bbl). During the nine months ended September 30, 2007, our commodity price hedges decreased oil revenues by $3.3 million ($1.57 per Bbl). The effect of the commodity price hedges in decreasing oil revenues during the nine months ended September 30, 2008 compared to their effect of decreasing oil revenues during the nine months ended September 30, 2007 was the result of (i) a higher average market price of NYMEX crude oil of $113.49 per Bbl in 2008 as compared to $66.21 per Bbl in 2007 and (ii) the greater price difference between NYMEX and the weighted average hedge price in 2008 as compared to 2007, partially offset by a lower amount of hedged volumes of 712,000 Bbls in 2008 as compared to 805,350 Bbls in 2007.

During the nine months ended September 30, 2008, our commodity price hedges decreased gas revenues by $0.2 million ($0.03 per Mcf) as a result of the amount reclassified from AOCI into natural gas revenues from cash flow hedges that were dedesignated as of June 30, 2007. Cash settlements for these dedesignated natural gas contracts are being recorded as a gain on derivatives not designated as hedges. During the nine months ended September 30, 2007, our commodity price hedges increased gas revenues by $0.9 million ($0.10 per Mcf) primarily as a result of the amount reclassified from AOCI to natural gas revenues from cash flow hedges that were dedesignated at June 30, 2007.

Production expenses. The following tables provide the components of our total oil and gas production costs for the nine months ended September 30, 2008 and 2007:

	Nine Months Ended September 30,			
	2008		2007	
(in thousands, except per unit amounts)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**
Lease operating expenses	$ 28,576	$ 1.00	$ 19,966	$ 0.92
Taxes:				
Ad valorem	1,798	0.06	1,437	0.07
Production	34,842	1.22	15,616	0.72
Workover costs	699	0.02	906	0.04
Total oil and gas production expenses	$ 65,915	$ 2.31	$ 37,925	$ 1.75

Among the cost components of production expenses, in general, we have management control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $28.6 million ($1.00 per Mcfe) for the nine months ended September 30, 2008, an increase of $8.6 million (43%) from $20 million ($0.92 per Mcfe) for the nine months ended September 30, 2007. The increase in lease operating expenses is due to (i) the wells acquired in the Acquisition, which increased the absolute and per unit amount because those wells have a higher per unit cost as compared to our historical per unit cost, (ii) our new wells successfully drilled and completed in 2008 and (iii) general inflation of field service and supply costs associated with rising commodity prices.

Ad valorem taxes have increased primarily as a result of (i) the Acquisition and (ii) the increase in commodity prices.

Table of Contents

Production taxes per unit of production were $1.22 per Mcfe during the nine months ended September 30, 2008, an increase of 69% from $0.72 per Mcfe during the nine months ended September 30, 2007. The increase is directly tied to the increase in oil and gas revenues and the related increase in commodity prices. Over the same period our natural gas equivalent prices (before the effects of hedging) increased 72%.

Workover expenses were $0.7 million and $0.9 million for the nine months ended September 30, 2008 and 2007, respectively. The 2008 amount related primarily to workovers in Andrews County, Texas, while the 2007 amount related to a workover project on a property located in Gaines County, Texas.

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

	Nine Months Ended September 30,	
(in thousands)	**2008**	**2007**
Geological and geophysical	$ 2,428	$ 993
Exploratory dry holes	2,778	16,222
Leasehold abandonments and other	15,082	895
Total exploration and abandonments	$20,288	$18,110

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, during the nine months ended September 30, 2008 was $2.4 million, an increase of $1.4 million from $1.0 million for the nine months ended September 30, 2007. This increase is primarily attributable to a comprehensive seismic survey on our New Mexico shelf properties which was initiated in December 2007.

Our exploratory dry hole expense during the nine months ended September 30, 2008 is primarily attributable to an unsuccessful operated exploratory well located in Eddy County, New Mexico. Our exploratory dry hole expense during the nine months ended September 30, 2007 is primarily attributable to five unsuccessful operated exploratory wells. 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 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 Eddy County, New Mexico, which was determined to be unsuccessful. Exploration expense of $1.4 million related to two unsuccessful outside operated wells located in Eddy County, New Mexico was also recorded.

For the nine months ended September 30, 2008, we recorded $15.1 million of leasehold abandonments, which are primarily related to one prospect in Culberson County, Texas, and a portion of our Fayetteville acreage in Arkansas. For the nine months ended September 30, 2007, we recorded $0.9 million of leasehold abandonments, the majority of which was related to one prospect located in Edwards County, Texas.

Table of Contents

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the nine months ended September 30, 2008 and 2007:

	Nine Months Ended September 30,			
	2008		2007	
(in thousands, except per unit amounts)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**
Depletion of proved oil and gas properties	$ 74,238	$ 2.60	$ 54,306	$ 2.50
Depreciation of other property and equipment	1,258	0.04	730	0.03
Amortization of intangible asset operating rights	326	0.01		
Total depletion, depreciation and amortization	$ 75,822	$ 2.65	$ 55,036	$ 2.53
Crude oil price used to estimate proved oil reserves at quarter end	$ 97.00		$ 78.25	
Natural gas price used to estimate proved gas reserves at quarter period end	$ 7.12		$ 6.38	

Depletion of proved oil and gas properties was $74.2 million ($2.60 per Mcfe) for the nine months ended September 30, 2008, an increase of $19.9 million from $54.3 million ($2.50 per Mcfe) for the nine months ended September 30, 2007. The increase in depletion expense was primarily due to (i) the Acquisition for which the depletion rate was $3.25 per Mcfe for the three months ended September 30, 2008 and (ii) capitalized costs associated with new wells that were successfully drilled and completed in 2007 and 2008. The increase was partially offset by the increase in the oil and natural gas prices, as noted above, between the quarters which were utilized to determine the proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the Acquisition. The intangible asset is currently being amortized over an estimated life of approximately 25 years.

Impairment of long-lived assets. In accordance with SFAS No. 144, we periodically 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, 2008, we recognized a non-cash charge against earnings of $2.8 million, which was comprised primarily of a field in Eddy County, New Mexico. For the nine months ended September 30, 2007, we recognized a non-cash charge against earnings of $4.6 million, 44% of which related to a field in Schleicher County, Texas, 28% of which related to a field in Crane County, Texas, and 8% of which related to a field in Mountrail County, North Dakota.

General and administrative expenses. The following table provides components of our general and administrative expenses for the nine months ended September 30, 2008 and 2007:

	Nine Months Ended September 30,			
	2008		2007	
(in thousands, except per unit amounts)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**
General and administrative expenses recurring	$ 22,352	$ 0.78	$ 14,763	$ 0.68
Non-recurring bonus paid to Henry Entities employees, see Note L	2,367	0.08		
Non-cash stock-based compensation stock options	3,376	0.12	1,649	0.08
Non-cash stock-based compensation restricted stock	1,578	0.06	1,007	0.05

Less: Third-party operating fee reimbursements	(2,629)	(0.09)	(852)	(0.04)
Total general and administrative expenses	$ 27,044	$ 0.95	$ 16,567	$ 0.77

General and administrative expenses were $27.0 million ($0.95 per Mcfe) for the nine months ended September 30, 2008, an increase of $10.5 million (63%) from $16.6 million ($0.77 per Mcfe) for the nine months ended September 30, 2007. The increase in general and administrative expenses during the nine months ended September 30, 2008 over the nine months ended September 30, 2007 was primarily due to (i) the non-recurring bonus paid to Henry Entities employees, (ii) an increase in non-cash stock-based compensation for both stock options and restricted stock awards and (iii) an increase in the number of employees and related personnel expenses, partially offset by an increase in third-party operating fee reimbursements.

As part of the Acquisition, we agreed to pay certain of the Henry Entities employees a predetermined bonus amount, in addition to the compensation we pay these employees, over the next two years. Since these employees will earn this bonus over the next two years we are reflecting the cost in our general and administrative costs. We are reflecting this bonus amount as non-recurring as it is not controlled by our management. See Note L for additional information related to this bonus.

We earn reimbursements as operator of certain oil and gas properties in which we own interests. As such, we earned reimbursements of $2.6 million and $0.9 million during the nine months ended September 30, 2008 and 2007, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in this reimbursement is directly related to the Acquisition, as we own a lower working interest in these operated properties compared to our historical property base, thus we have a larger third-party reimbursement as compared to our historical property base.

Bad debt expense. On May 20, 2008, we entered into a short-term purchase agreement with an oil purchaser to buy a portion of the oil affected as a result of the New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared bankruptcy. We fully reserved the receivable amount due from this purchaser for June and July production of approximately $2.9 million during the nine months ended September 30, 2008.

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

Gain on derivatives not designated as hedges. As discussed in Note J, during the three months ended June 30, 2007, we determined that all of our natural gas commodity derivative contracts no longer qualified as hedges under the requirements of SFAS No. 133. If the hedge is no longer highly effective, according to SFAS No. 133, an entity shall discontinue hedge accounting for an existing hedge, prospectively, and during the period the hedges became ineffective. In addition, for our new commodity derivative contracts entered into after August 2007, we chose not to designate any of these contracts as hedges. As a result, any changes in fair value and any cash settlements related to these contracts are recorded in earnings during the related period.

For the nine months ended September 30, 2008, the related cash payments for settlements for derivative contracts not designated as hedges was approximately $29.2 million. The non-cash mark-to-market adjustment for the derivative contracts not designated as hedges was a gain of $72.8 million. This is compared to cash receipts for settlements of $1.3 million and non-cash mark-to-market gains of $1.8 million for the nine months ended September 30, 2007.

Interest expense. Interest expense was $19.8 million for the nine months ended September 30, 2008, a decrease of $10.0 million from $29.8 million for the nine months ended September 30, 2007. The weighted average interest rate for the nine months ended September 30, 2008 and 2007 was 5.1% and 7.8%, respectively. The weighted average debt balance during the nine months ended September 30, 2008 and 2007 was approximately $389.9 million and $472.4 million, respectively.

The decrease in weighted average debt balance during the nine months ended September 30, 2008 was due to (i) the partial prepayment in August 2007 of $86.6 million on the 2nd Lien Credit Facility and the repayment in August 2007 of $86.6 million on our previous revolving credit facility and (ii) a partial prepayment in March 2008 on our previous revolving credit facility utilizing cash from operations, offset by borrowings in July 2008 for the Acquisition. Also, in July 2008, we repaid and terminated the 2nd Lien Credit Facility which resulted in the write-off of approximately $1.1 million of deferred loan costs and approximately $0.4 million of original issue discount, both of which are included in interest expense. In March 2007, we reduced our previous revolving credit facility s borrowing base by $100.0 million, or 21%, resulting in the write-off of $0.8 million of deferred loan costs, and repaid a term credit facility, resulting in the write-off of $0.4 million of deferred loan costs, both of which are included in interest expense. In August 2007, we made a $86.6 million partial prepayment on our 2nd Lien Credit Facility from proceeds of our initial public offering, which resulted in the write-off of approximately $1.0 million of deferred loan costs and approximately $0.4 million of original issue discount, both of which are included in interest expense. The decrease in the weighted average interest rate is due to (i) improvement in market interest rates and (ii) the fact that the interest rate margins under the Senior Credit Facility (and previous revolving credit facility) were lower than those under the 2nd Lien Credit Facility.

Income tax provisions. We recorded an income tax expense of $96.2 million and $13.3 million for the nine months ended September 30, 2008 and 2007, respectively. The effective income tax rate for the nine months ended September 30, 2008 and 2007 was 39.1% and 42.9%, respectively. We estimated a higher effective state income rate in 2007 than in 2008, which is primarily due to our estimate of income among the various states in which we own assets.

Capital commitments, capital resources and liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, proceeds from the disposition of assets or alternative financing sources as discussed in Capital resources below.

Oil and gas properties. Our capital expenditures on oil and gas properties, excluding acquisitions and asset retirement obligations, during the nine months ended September 30, 2008 and 2007 totaled $229.5 million and $115.2 million, respectively. These expenditures were primarily funded by cash flow from operations.

On August 7, 2008, our board of directors approved an increase in our 2008 capital budget to $389.3 million. Currently, we expect to expend approximately $355 million of this approved budget in 2008. On November 6, 2008, our board of directors approved a capital budget for 2009 of up to approximately $500 million. The capital budget is predicated on us funding it substantially within our cash flow. If commodity prices continue their decline, and considering other factors that may change, we expect we would curtail our spending such that we spend substantially within our cash flow.

Other than leasehold acreage and other property interests, our 2008 and 2009 capital budgets are exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and gas properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations and that will allow us to apply our operating expertise.

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 our cash flows will be sufficient to satisfy our 2008 and 2009 capital budgets; however, we could use our credit facility to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. In addition, under certain circumstances we would consider increasing or reallocating our 2008 and 2009 capital budgets.

Acquisitions. Our expenditures for acquisitions of proved and unproved properties during the nine months ended September 30, 2008 and 2007 totaled $815.2 million and $9.6 million, respectively. The Henry Properties acquisition in July 2008 was primarily funded by a private placement of the Company s common stock and borrowings under our credit facility.

Contractual obligations, including off-balance sheet obligations. Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, and other liabilities. From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At September 30, 2008, the material off-balance sheet arrangements and transactions that we have entered into included (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, and (iv) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices. Other than the off-balance sheet arrangements described above, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources. Since December 31, 2007, the material changes in our contractual obligations included a $309.6 million increase in outstanding long-term borrowings, a $26.3 million decrease in our net commodity derivative obligations, and a $19.1 million increase in our drilling commitments. See Note K of Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information regarding our long-term debt and Item 3. Quantitative and Qualitative Disclosures About Market Risk for information regarding the interest on our long-term debt and information on changes in the fair value of our open derivative obligations during the nine months ended September 30, 2008.

In accordance with GAAP, we periodically measure and record certain financial assets and liabilities at fair value. Effective January 1, 2008, we adopted the provisions of SFAS 157 for which delayed adoption is not provided under FSP FAS 157-1. SFAS 157 retains the exchange price notion in the definition of fair value but clarifies that the exchange price is the price in an orderly transaction between market participants to sell an asset or transfer a liability in the principal or most advantageous market in which the reporting company would transact for the asset or liability.

The financial assets and liabilities that we periodically measure and record at fair value are primarily the commodity derivative contracts. See Note E of Condensed Notes to Consolidated Financial Statements Unaudited included in Item 1. Consolidated Financial Statements (Unaudited) for additional information regarding the financial assets and liabilities and the valuation techniques used to measure the fair values.

Our commodity derivative contracts that are periodically measured and recorded at fair value represent those derivative contracts that continue to be subject to market or credit risk. At September 30, 2008, these contracts represented net liabilities of $18.8 million. The ultimate liquidation value of our commodity derivatives will be dependent upon actual future commodity prices, which may differ materially from the inputs used to determine the derivative contracts fair values at September 30, 2008. We enter into these derivative contracts for the primary purpose of hedging commodity price risk on forecasted physical commodity sales and have an expectation of a high degree of correlation between changes in the derivative contract values and the hedged risks. See Note J of Condensed Notes to Consolidated Financial Statements Unaudited included in Item 1. Consolidated Financial Statements (Unaudited) and Item 3. Quantitative and Qualitative Disclosures About Market Risk for additional information about our derivative contracts and market risk.

Capital resources. Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our credit facilities. We believe that funds from operating cash flows and our credit facility should be sufficient to meet both our short-term working capital requirements and our 2008 and 2009 capital budget plans.

Cash flow from operating activities. Our net cash provided by operating activities was $319.4 million and $102.9 million for the nine months ended September 30, 2008 and 2007, respectively. The increase in operating cash flows during the nine months ended September 30, 2008 over 2007 was principally due to (i) increases in our oil and gas production as a result of our exploration and development program, (ii) two months of activity from the acquired Henry Properties and (iii) increases in average realized oil and natural gas prices.

Cash flow used in investing activities. During the nine months ended September 30, 2008 and 2007, we invested $800.6 million and $114.2 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, 2008, primarily due to the Acquisition, as well as increased drilling activity in 2008. In order to preserve liquidity, we reduced our drilling activities and curtailed capital expenditures during the nine months ended September 30, 2007, until we were able to complete our second lien term loan facility in March 2007.

Cash flow from financing activities. Net cash provided by financing activities was $540.0 million and $30.8 million for the nine months ended September 30, 2008 and 2007, respectively. During the nine months ended September 30, 2008, we borrowed $767.8 million under our credit facilities and issued approximately 8.3 million shares of our common stock to fund the Acquisition. In March 2007, we entered into a $200 million 2nd Lien Credit Facility. The proceeds were principally used to repay the outstanding balance under our prior term loan facility and to reduce the outstanding balance under our credit facility.

On July 31, 2008, we amended and restated our senior credit facility in various respects, including increasing the borrowing base to $960 million, subject to scheduled semiannual redeterminations, and extending the maturity date from February 24, 2011 to July 31, 2013. We paid an arrangement fee of $14.4 million at closing of the Senior Credit Facility. In October 2008, the borrowing base was reaffirmed at $960 million. The amount outstanding under the Senior Credit Facility at September 30, 2008 was $635.0 million. Between scheduled borrowing base redeterminations we and, if requested by 66 2/3 percent of the lenders, the lenders may each request one special redetermination.

Advances on the Senior Credit Facility bear interest, at our option, based on (a) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 125 to 275 basis points and zero to 125 basis points, respectively, per annum depending on the balance outstanding. We pay commitment fees on the unused portion of the available borrowing base ranging from 25 to 50 basis points per annum. Our Senior Credit Facility bore interest at 4.00% per annum at September 30, 2008.

On July 31, 2008, we repaid the all the amounts outstanding under our 2nd Lien Credit Facility and terminated the facility.

On May 19, 2008, we entered into a third amendment to our credit facility, which redetermined the borrowing base under the first lien credit facility to $550 million at June 30, 2008 and extended the maturity date to February 24, 2011. We incurred approximately $1.0 million in loan costs associated with this amendment.

On June 5, 2008, we entered into a common stock purchase agreement with certain unaffiliated third-party investors to sell certain shares of our common stock in a private placement (the Private Placement) contemporaneous with the closing of the Acquisition. On July 31, 2008, we issued 8,302,894 shares of our common stock at $30.11 per share pursuant to the Private Placement. We paid the placement agent of the Private Placement a fee of approximately $7.6 million, which resulted in net proceeds to us of $242.4 million.

In conducting our business, we may utilize various financing sources, including (a) fixed and floating rate debt, (b) convertible securities, (c) preferred stock and (d) common stock. We may also sell assets and issue securities in exchange for oil and gas assets or interests in oil and gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our Senior Credit Facility.

Financial markets. The current state of the financial markets is uncertain. There have been financial related institutions that have (a) failed and been forced into government receivership, (b) declared bankruptcy, (c) been forced to seek additional capital and liquidity to maintain viability or (d) merged to survive. The U.S. and world economy is experiencing a slow-down which is having an adverse impact on the financial markets.

At September 30, 2008, we had $324.7 million of borrowing capacity under our Senior Credit Facility. Even in light of the current uncertainty in the financial markets, we currently believe that our lenders under our Senior Credit Facility have the ability to fund additional borrowings we may need for our business.

We currently pay floating rate interest under our Senior Credit Facility and we are unable to predict, especially in light of the current uncertainty in the financial markets, whether we will incur increased interest costs due to rising interest rates. However, we are evaluating the use of interest rate derivatives that could mitigate the cost of rising interest rates.

In the current financial markets, we do not believe that we could refinance our Senior Credit Facility and obtain comparable terms. Since our Senior Credit Facility matures in July 2013, we have no immediate need to seek refinancing of our Senior Credit Facility.

To the extent we need additional funds, beyond those available under our Senior Credit Facility, to operate our business or make acquisitions we would have to pursue other financing sources. These sources could include issuance of (a) fixed and floating rate debt, (b) convertible securities, (c) preferred stock, (d) common stock or (e) other securities. We may also sell assets. However, in light of the current financial markets there are no assurances that we could obtain additional funding, or if available, at what cost and terms.

Liquidity. Our principal sources of short-term liquidity are cash on hand and unused borrowing capacity under our Senior Credit Facility. At September 30, 2008, we had $324.7 million of unused borrowing capacity and $54.4 million of cash on hand.

Book capitalization and current ratio. Our book capitalization at September 30, 2008 was $1,823.7 million, consisting of debt of $635.0 million and stockholders equity of $1,188.7 million. Our debt to book capitalization was 35 percent and 30 percent at September 30, 2008 and December 31, 2007, respectively. Our ratio of current assets to current liabilities was 0.79 to 1.00 at September 30, 2008 as compared to 0.84 to 1.00 at December 31, 2007.

Inflation and changes in prices. Our revenues, the value of our assets, our ability to obtain bank funding or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that are beyond our ability to control or predict. During the third quarter of 2008, we received an average of $114.44 per barrel of oil and $10.12 per Mcf of natural gas before consideration of commodity derivative contracts compared to $69.91 per barrel of oil and $7.61 per Mcf of natural gas in the same period of the prior year. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and continued through the first six months of 2008, commodity prices for oil and gas increased significantly. The higher prices have led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs but also on capital costs. We expect these costs to moderate for the remainder of 2008 and into 2009 as a result of the recent rapid diminution in prices for oil and natural gas.

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, 2008. See our disclosure of critical accounting policies in the consolidated financial statements on our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on March 28, 2007.

Recent accounting pronouncements

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

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

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

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

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

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

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

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. FSP EITF 03-6-1 is effective for us on January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) will be adjusted retroactively to conform to its provisions. Early application of FSP EITF 03-6-1 is not permitted. Although restricted stock awards meet this definition, we do not expect the application of FSP EITF 03-6-1 to have a significant impact on our reported earnings per share.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. This statement is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*. We do not expect the adoption of SFAS No. 162 to have an impact on our financial statements.

In October 2008, the FASB issued FASB Staff Position (FSP) No. SFAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active*. FSP No. SFAS 157-3 clarifies the application of SFAS No. 157 as it relates to the valuation of financial assets in a market that is not active for those financial assets. This FSP is effective immediately and includes those periods for which financial statements have not been issued. We currently do not have any financial assets that are valued using inactive markets, and as a result, we are not impacted by the issuance of FSP No. SFAS 157-3.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

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

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

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

Commodity price risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of oil and natural gas we have entered into, and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our common stock. As of September 30, 2008, the net unrealized loss on our commodity price risk management contracts was $18.8 million. An average increase in the commodity price of $1.00 per barrel of crude oil and $0.10 per Mcf for natural gas from the commodity prices as of September 30, 2008, would have resulted in an increase in the net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet as of September 30, 2008, of approximately $5.0 million.

At September 30, 2008, we had an oil price collar and oil price swaps that settle on a monthly basis covering future oil production from October 1, 2008 through December 31, 2012. See Commodity Derivatives and Hedging. Subsequent to September 30, 2008, oil futures prices have decreased. The average NYMEX oil futures price for the quarter ended September 30, 2008, was $118.52. As of October 31, 2008, the NYMEX oil futures price was $67.81. The decrease in oil prices, should it continue through the end of the fourth quarter of 2008, should decrease the fair value liability of our commodity derivative contracts from their recorded balance at September 30, 2008. Changes in the recorded fair value of the undesignated commodity derivative contracts are marked to market through earnings as unrealized gains or losses. The potential decrease in fair value liability would be recorded in earnings as unrealized gains. However, an increase in the average NYMEX oil futures price above the third quarter average would result in an increase in fair value liability and unrealized losses in earnings. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

Interest rate risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our bank credit facilities, and the terms of our revolving credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. We had total indebtedness of $635.0 million outstanding under our Senior Credit Facility at September 30, 2008. The impact of a 1% increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $6.4 million and a corresponding decrease in net income before income tax.

Item 4. Controls and Procedures

Evaluation of disclosure 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, 2008, our disclosure controls and procedures were effective, in all material respects, to ensure that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

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

Changes in Internal Control Over Financial Reporting. During the third quarter of 2008, we completed the acquisition of the Henry Properties. Because of the timing of the acquisition, management anticipates that it will not include the internal control processes of these related entities in its 2008 internal controls assessment to be included in our Annual Report for the year ending December 31, 2008. The acquisition is excluded from the certifications required under Section 302 of the Sarbanes-Oxley Act of 2002. We will include all aspects of internal controls over financial reporting for this acquisition, including changes to our internal controls over financial reporting based on this acquisition, in our 2009 assessment.

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are party to the legal proceedings that are described under Legal actions in Note L of Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited). We are also party to other proceedings and claims incidental to its business. While many of these other matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations.

Item 1A. Risk Factors

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC, including, but not limited to, our most recent Annual Report on Form 10-K, before investing in our shares. Any information presented in this report on a pro forma basis has been prepared as if (a) the closing of the acquisition of Henry Petroleum LP, certain affiliated entities and the related along-side interests, (b) entering into our new credit facility and (c) issuance of our common stock in the private placement occurred on January 1, 2007.

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our shares could decline and you could lose all or part of your investment.

Risks Related to Our Business

Crude oil and natural gas prices are volatile. A decline in crude oil and natural gas prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and gas properties depend primarily upon the prices we receive for our crude oil and natural gas production and the prices prevailing from time to time for crude oil and natural gas. Crude oil and natural gas prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of our cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for crude oil and natural gas are subject to a variety of factors, including:

- the level of consumer demand for crude oil and natural gas;
- the domestic and foreign supply of crude oil and natural gas;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign crude oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain crude oil price and production controls;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;
- political conditions or hostilities in oil and gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption; and

worldwide economic conditions.

Table of Contents

Furthermore, recent crude oil and natural gas prices have been particularly volatile. For example, the NYMEX crude oil spot price for the period between January 1, 2008 and October 31, 2008 has ranged from a high of $145.29 to a low of $62.73 and the NYMEX natural gas spot price for the period between January 1, 2008 and October 31, 2008 has ranged from a high of $13.58 to a low of $6.12.

Declines in crude oil and natural gas prices would not only reduce our revenue, but could reduce the amount of crude oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. If the oil and gas industry experiences significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can affect the value of our common stock.

Drilling for and producing crude oil and natural gas are high-risk activities with many uncertainties that could cause our expenses to increase or our cash flows and production volumes to decrease.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our crude oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable crude oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in crude oil and natural gas prices;
- surface access restrictions;
- loss of title or other title related issues;
- crude oil, natural gas liquids or natural gas gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for crude oil and natural gas.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of crude oil and/or natural gas that cannot be measured in an exact manner. Estimates of economically recoverable crude oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;

the quality, quantity and interpretation of available relevant data;

the assumed effects of regulations by governmental agencies;

the quality, quantity and interpretation of available relevant data;

the assumed effects of regulations by governmental agencies;

assumptions concerning future commodity prices; and

assumptions concerning future operating costs; severance, ad valorem and excise taxes; development costs; and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

the quantities of crude oil and natural gas that are ultimately recovered;

the production and operating costs incurred;

the amount and timing of future development expenditures; and

future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. For example, the estimated discounted future net cash flows from our proved reserves at December 31, 2007 were calculated using $92.50 per Bb1 Plains Marketing, L.P. West Texas Intermediate posted crude oil price and $6.795 per MMBtu NYMEX Henry Hub spot natural gas price, adjusted for location and quality by field, while the actual future net cash flows also will be affected by factors such as:

the amount and timing of actual production;

levels of future capital spending;

increases or decreases in the supply of or demand for oil and gas; and

changes in governmental regulations or taxation.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. It requires the use of commodity prices, as well as operating and development costs, prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for crude oil and natural gas production because of seasonal price fluctuations or other varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the ten percent discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and gas industry in general. Therefore, the estimates of discounted future net cash flows or Standardized Measure included herein should not be construed as accurate estimates of the current market value of our proved reserves.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our crude oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of crude oil and natural gas reserves. At September 30, 2008, total debt outstanding under our credit facility was $635.0 million, and $324.7 million was available to be borrowed. Expenditures for exploration and development of oil and gas properties are the primary use of our capital resources. On a pro forma basis, we invested approximately

Table of Contents

$250 million in 2007 and anticipate investing over $400 million in 2008 for acquisition, exploration and development activities on our properties, excluding the cost of the acquisition of Henry Petroleum LP, certain affiliated entities and the related acquisition of the along-side interests.

We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our outstanding common stock. Additional borrowings under our credit facility or the issuance of additional debt will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the facility, which consent may be withheld by the lenders under our credit facility in their discretion. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of crude oil and natural gas we are able to produce from existing wells;
- the prices at which our crude oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. As a result, we may require additional capital to fund our operations, and we may not be able to obtain debt or equity financing to satisfy our capital requirements. If cash generated from operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

We may not be able to obtain funding at all, or obtain funding on acceptable terms, to meet our future capital needs because of the deterioration of the credit and capital markets.

Global financial markets and economic conditions have been, and will likely continue to be, disrupted and volatile. The debt and equity capital markets have become uncertain. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding.

In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. Also, as a result of concern about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide funding to borrowers.

In addition, our ability to obtain capital under our credit facility may be impaired because of the recent downturn in the financial market, including the issues surrounding the solvency of certain institutional lenders and the recent failure of several banks.

Specifically, we may be unable to obtain adequate funding under our credit facility because:

- our lending counterparties may be unwilling or unable to meet their funding obligations;

the borrowing base under our credit facility is redetermined at least twice a year and may decrease due to a decrease in crude oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for other reasons; or if any lender is unable or unwilling to fund their respective portion of any advance under our credit facility, then the other lenders thereunder are not required to provide additional funding to make up the portion of the advance that the defaulting lender refused to fund.

Due to these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Almost all of our producing properties are located in the Permian Basin region of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

Our producing properties are geographically concentrated in the Permian Basin region of Southeast New Mexico and West Texas. On a pro forma basis, at December 31, 2007, approximately 99% of our PV-10 was attributable to properties located in the Permian Basin. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, curtailment of production or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids produced from the wells in this area.

In addition to the geographic concentration of our producing properties described above, on a pro forma basis, at December 31, 2007, approximately (i) 46% of our proved reserves were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and gas properties located in Southeast New Mexico; and (ii) 15% of our proved reserves were attributable to the Wolfberry play in West Texas, which is the term applied to combined production from the Wolfcamp and Spraberry horizons in this area of the Permian Basin, a play in which we acquired interests as a result of the acquisition of Henry Petroleum LP, certain affiliated entities and the related acquisition of the along-side interests. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

Future price declines could result in a reduction in the carrying value of our proved oil and gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our oil and gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and gas properties, the carrying value may not be recoverable and therefore require a write-down. We may incur impairment charges in the future, which could materially affect our results of operations in the period incurred.

Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

The results of our exploratory drilling in new or emerging areas are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Our commodity price risk management program may cause us to forego additional future profits or result in our making cash payments to our counterparties.

To reduce our exposure to changes in the prices of crude oil and natural gas, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our crude oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future crude oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in crude oil and natural gas prices in some circumstances, including the following:

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us;
- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or
- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties.

Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our common stock. At September 30, 2008, the net unrealized loss on our commodity price risk management contracts was approximately $18.8 million. An average increase in the commodity price of $1.00 per barrel of crude oil and $0.10 per Mcf for natural gas from the commodity prices at September 30, 2008 would have resulted in an increase in the net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet at September 30, 2008, of approximately $5.0 million. We may continue to incur significant unrealized losses in the future from our commodity price risk management activities to the extent market prices increase and our derivatives contracts remain in place.

We may enter into interest rate derivative instruments that would subject us to potential loss of income.

We may enter into derivative instruments designed to limit the interest rate risk under our current credit facility or any credit facilities we may enter into in the future. These derivative instruments would primarily involve the exchange of a portion of our floating rate interest obligations for fixed rate interest obligations or a cap on our exposure to floating interest rates to reduce our exposure to the volatility of interest rates. While we may enter into instruments limiting our exposure to higher market interest rates, we cannot assure you that any interest rate derivative instruments we implement will be effective; and furthermore, even if effective these instruments may not offer complete protection from the risk of higher interest rates.

All interest rate derivative instruments involve certain additional risks, such as:

- the counterparty may default on its contractual obligations to us;
- there may be issues with regard to the legal enforceability of such instruments;
- the early repayment of one of our interest rate derivative instruments could lead to prepayment penalties; or
- unanticipated and significant changes in interest rates may cause a significant loss of basis in the instrument and a change in current period expense.

If we enter into derivative instruments that require us to post cash collateral, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures. Future collateral requirements will depend on arrangements with our counterparties and highly volatile crude oil and natural gas prices and interest rates.

Our identified inventory of drilling locations and recompletion opportunities are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled the drilling and recompletion of our drilling and recompletion opportunities as an estimation of our future multi-year development activities on our existing acreage. On a pro forma basis, at June 30, 2008, we had identified 3,293 drilling locations with proved undeveloped reserves attributable to 967 of such locations, and 1,389 recompletion opportunities with proved undeveloped reserves attributed to 588 of such opportunities. These identified opportunities represent a significant part of our growth strategy. Our ability to drill and develop these opportunities depends on a number of uncertainties, including (1) our ability to timely drill wells on lands subject to complex development terms and circumstances; and (2) the availability of capital, equipment, services and personnel, seasonal conditions, regulatory and third party approvals, crude oil and natural gas prices, and drilling and recompletion costs results. Because of these uncertainties, we may never drill or recomplete the numerous potential opportunities we have identified or produce crude oil or natural gas from these or any other potential opportunities. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, revenues and results of operations.

On a pro forma basis, approximately 44% of our total estimated net proved reserves at December 31, 2007, were undeveloped, and those reserves may not ultimately be developed.

On a pro forma basis, at December 31, 2007, approximately 44% of our total estimated net proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. If we choose not to spend the capital to develop these reserves, or if we are not able to successfully develop these reserves, we will be required to write-off these reserves. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our common stock.

Because we do not control the development of the properties in which we own interests, but do not operate, we may not be able to achieve any production from these properties in a timely manner.

On a pro forma basis, at December 31, 2007, approximately 9% of our PV-10 was attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on such nonoperated properties depend upon a number of factors, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operators expertise and financial resources;
- the approval of other participants in such properties; and
- the selection of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines, which may adversely affect our production, revenues and results of operations.

Unless we replace our crude oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our common stock.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing crude oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our common stock and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

We may be unable to make attractive acquisitions or integrate acquired companies, and any inability to do so may disrupt our business and hinder our ability to grow through the acquisition of businesses.

One aspect of our business strategy calls for acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our credit facility imposes certain direct limitations on our ability to enter into mergers or combination transactions involving our company. Our credit facility also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses. If we desire to engage in an acquisition that is otherwise prohibited by our credit facility, we will be required to seek the consent of our lenders in accordance with the requirements of the facility, which consent may be withheld

by the lenders under our credit facility in their discretion. Furthermore, given the current situation in the credit markets, many leaders are reluctant to provide consents in any circumstances, including to allow accretive transactions.

If we acquire another business, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

If we are unable to integrate Henry Petroleum LP, the affiliated entities and the related along-side interests as expected, our future financial performance may be negatively impacted.

The integration of acquired businesses and operations with our existing business and operations has been and will continue to be a complex, time-consuming and costly process, specifically including the Henry Entities businesses and operations, given that Henry Petroleum LP, the affiliated entities and the related along-side interests substantially increased our size and diversified the geographic areas in which we operate. A failure to successfully integrate the Henry Entities businesses and operations with our existing and other business and operations in a timely manner may have a material adverse effect on our production, revenues and results of operations. The difficulties of combining the acquired operations include, among other things:

- operating a larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business;
- vendor or key employee losses from the acquired business;
- changes in key supply relationships related to the acquired business;
- integrating personnel from diverse business backgrounds and organizational cultures;
- developing and maintaining an effective system of internal controls related to the acquired business;
- integrating internal controls, compliance under the Sarbanes-Oxley Act of 2002 and other regulatory compliance and corporate governance matters;
- an inability to complete other internal growth projects and/or acquisitions due to constraints on time and resources;
- difficulties integrating new technology systems that we have not historically used in our operations or financial reporting;
- an increase in our indebtedness;
- potential environmental or regulatory compliance matters or liabilities including, but not limited to potential matters associated with the Environmental Protection Agency and the Texas Commission on Environmental Quality, and title issues, including liabilities arising from the operation of the acquired business before the acquisition; and
- coordinating and consolidating corporate and administrative functions.

Further, unexpected costs, liabilities and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing, or a reduction or elimination of, the expected benefits of the acquisition.

The acquisition of Henry Petroleum LP, certain affiliated entities and the related acquisition of the along-side interests could expose us to potentially significant liabilities.

In connection with the acquisition of Henry Petroleum LP, certain affiliated entities and the related acquisition of the along-side interests, we purchased all of the sellers   interests in the Henry Entities, rather than individual assets; therefore, the Henry Entities retained their liabilities, subject to certain exclusions and limitations contained in the purchase agreement, including certain unknown and contingent liabilities. We performed due diligence in connection with the acquisition of Henry Petroleum LP, certain affiliated entities and the related acquisition of the along-side interests and attempted to verify the representations of the sellers and of the former management of the Henry Entities, but there may be threatened, contemplated or contingent claims against the Henry Entities related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware. Although the sellers agreed to indemnify us on a limited basis against certain liabilities, these indemnification obligations will expire over time and expose us to unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Properties acquired may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

We obtained the majority of our current reserve base through acquisitions of producing properties and undeveloped acreage, including those owned by the Henry Entities. We expect acquisitions will continue to contribute to our future growth. Successful acquisitions of oil and gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future crude oil and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties.

Competition in the oil and gas industry is intense, making it more difficult for us to acquire properties, market crude oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing crude oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market crude oil and natural gas and secure trained personnel and increased compensation for trained personnel could have a material adverse effect on our production, revenues and results of operations.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with crude oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher crude oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our exploration and development drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. Drilling for crude oil and natural gas often involves unprofitable efforts, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increases in the cost of, or shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We periodically evaluate our unproved oil and gas properties, and could be required to recognize noncash charges in the earnings of future periods.

At September 30, 2008, we carried unproved property costs of $445.4 million. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. These evaluations will be affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize noncash charges in the earnings of future periods.

We may incur substantial losses and be subject to substantial liability claims as a result of our crude oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our crude oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;

damage to and destruction of property, natural resources and equipment;

pollution and other environmental damage;

Table of Contents

- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

Market conditions or operational impediments may hinder our access to crude oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory crude oil and natural gas processing or transportation arrangements may hinder our access to crude oil and natural gas markets or delay our production. The availability of a ready market for our crude oil and natural gas production depends on a number of factors, including the demand for and supply of crude oil and natural gas, the proximity of reserves to pipelines and terminal facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering and transportation systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil, natural gas liquids or natural gas pipeline or gathering, transportation or processing capacity. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations.

Our crude oil and natural gas exploration, development and production, and saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production of, crude oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our production, revenues and results of operations.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our crude oil and natural gas exploration, development and production, and saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

Table of Contents

The loss of our chief executive officer or our chief operating officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of Timothy A. Leach, our chairman of the board and chief executive officer, Steven L. Beal, our president and chief operating officer, our other executive officers and our key employees who have extensive experience and expertise in evaluating and analyzing producing oil and gas properties and drilling prospects, maximizing production from oil and gas properties, marketing oil and gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.

We inject water into formations on some of our properties to increase the production of crude oil and natural gas. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of crude oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects.

Our indebtedness could restrict our operations and make us more vulnerable to adverse economic conditions.

We now have, and will continue to have, a significant amount of indebtedness, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. At September 30, 2008, our total debt was $635.0 million. Assuming our total debt outstanding at September 30, 2008 was held constant, if interest rates had been higher or lower by 1% per annum, our annual interest expense would have increased or decreased by approximately $6.4 million. At September 30, 2008, our total borrowing capacity under our credit facility was $960 million, of which $324.7 million was available.

Our current and future indebtedness could have important consequences to you. For example, it could:

- impair our ability to make investments and obtain additional financing for working capital, capital expenditures, acquisitions or other general corporate purposes;
- limit our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make principal and interest payments on our indebtedness;
- limit our ability to borrow funds that may be necessary to operate or expand our business;
- put us at a competitive disadvantage to competitors that have less debt;
- increase our vulnerability to interest rate increases; and
- hinder our ability to adjust to rapidly changing economic and industry conditions.

Our ability to meet our debt service and other obligations may depend in significant part on the extent to which we can successfully implement our business strategy. We may not be able to implement or realize the benefits of our business strategy.

Our credit facility imposes restrictions on us that may affect our ability to successfully operate our business.

Our credit facility limits our ability to take various actions, such as:

- incurring additional indebtedness;
- paying dividends;
- creating certain additional liens on our assets;

- entering into sale and leaseback transactions;
- making investments;
- entering into transactions with affiliates;
- making material changes to the type of business we conduct or our business structure;
- making guarantees;
- disposing of assets in excess of certain permitted amounts;
- merging or consolidating with other entities; and
- selling all or substantially all of our assets.

In addition, our credit facility requires us to maintain certain financial ratios and to satisfy certain financial conditions, which may require us to reduce our debt or take some other action in order to comply with each of them.

These restrictions could also limit our ability to obtain future financings, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our credit facility.

A terrorist attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for crude oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenue. Crude oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities we use for the production, transportation or marketing of our crude oil and natural gas production are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Relating to Our Common Stock

Our restated certificate of incorporation, amended and restated bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our restated certificate of incorporation, amended and restated bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;
- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than
66 2/3 % of the voting power of all outstanding voting stock;
- the prohibition of stockholder action by written consent; and

limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Table of Contents

Because we have no plans to pay dividends on our common stock, stockholders must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. The terms of our existing credit facility restricts the payment of dividends without the prior written consent of the lenders. Stockholders must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may issue securities to raise cash for acquisitions, the payment of our indebtedness or other purposes. We may also acquire interests in other companies by using a combination of cash and our common stock or solely our common stock. We may also issue securities convertible into our common stock. Any of these events may dilute your ownership interest in us and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

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

None.

Table of Contents

Item 6. Exhibits

Exhibit Number	Exhibit
10.1	Indemnification Agreement, dated August 25, 2008, by and between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on August 29, 2008, and incorporated herein by reference).
10.2	Employment Agreement, dated August 25, 2008, by and between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on August 29, 2008, and incorporated herein by reference).
10.3	Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc., James C. Henry and Paula Henry, Henry Securities Ltd., Henchild LLC, Henry Family Investment Group, Henry Holding Lap, Henry Energy LP, Aguasal Holding, HELP Investment LLC, Henry Capital LLC, Henry Operating LLC, Henry Petroleum LP, Quail Ranch LLC, Aguasal Management LLC and Aguasal LP (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
10.4	Common Stock Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc. and the Purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
10.5	Registration Rights Agreement, dated July 31, 2008, by and between Concho Ressources Inc. and the Purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
10.6	Amended and Restated Credit Agreement, dated July 31, 2008, by and between Concho Resources Inc., JPMorgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
31.1 (a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2 (a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 (b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2 (b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(a) Filed herewith.

(b) Furnished herewith.

Table of Contents

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 13, 2008	By /s/ Timothy A. Leach
	Timothy A. Leach Director, Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)
	By /s/ Darin G. Holderness
	Darin G. Holderness Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)

64

Table of Contents

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