CONTINENTAL RESOURCES INC
Form 10-Q
November 07, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended September 30, 2008

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______

Commission File Number: 001-32886

CONTINENTAL RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
302 N. Independence, Suite 1500, Enid, Oklahoma	**73701**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (580) 233-8955

Former name, former address and former fiscal year, if changed since last report: Not applicable

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

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

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x Smaller reporting company ¨

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date. 169,163,507 common shares were outstanding on October 31, 2008.

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CONTINENTAL RESOURCES, INC.

FORM 10-Q

Quarter Ended September 30, 2008

Unless the context otherwise indicates, all references in this report to Continental , Company , we , us , or our are to Continental Resources, Inc. and its subsidiary.

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Glossary of Oil and Natural Gas Terms

The terms defined in this section are used throughout this report:

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Enhanced recovery. The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differ from nearby rock.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

MBoe. One thousand Boe.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Working interest. The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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PART I. Financial Information

ITEM 1. Financial Statements

On May 14, 2007, the Company completed its initial public offering. In conjunction therewith, the Company effected an 11 for 1 stock split by means of a stock dividend. All prior period share and per share information contained in this report have been retroactively restated to give effect to the stock split. On May 14, 2007, the Company amended its certificate of incorporation to, among other things, increase the number of authorized preferred shares to 25 million and common shares to 500 million. Prior to completion of the public offering, the Company was a subchapter S corporation and income taxes were payable by its shareholders. In connection with the public offering, the Company converted to a subchapter C corporation and recorded a charge to earnings of $198.4 million to recognize deferred taxes at May 14, 2007. Thereafter, the Company has provided for income taxes on income.

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Continental Resources, Inc. and Subsidiary

Condensed Consolidated Balance Sheets

	September 30, 2008 (Unaudited)	December 31, 2007
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 3,133	$ 8,761
Receivables:		
Oil and natural gas sales	119,176	95,165
Affiliated parties	38,268	17,146
Joint interest and other, net	142,320	50,779
Inventories	34,018	19,119
Deferred and prepaid taxes	690	12,159
Prepaid expenses and other	1,928	2,435
Total current assets	339,533	205,564
Net property and equipment, based on successful efforts method of accounting	1,765,848	1,157,926
Debt issuance costs, net	1,296	1,683
Total assets	$ 2,106,677	$ 1,365,173
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 291,736	$ 127,730
Accounts payable trade to affiliated parties	26,239	15,090
Accrued liabilities and other	42,805	25,295
Revenues and royalties payable	103,973	67,349
Unrealized derivative losses		26,703
Current portion of asset retirement obligation	2,720	3,939
Total current liabilities	467,473	266,106
Long-term debt	229,400	165,000
Other noncurrent liabilities:		
Deferred tax liability	415,406	271,424
Asset retirement obligation, net of current portion	41,649	38,153
Other noncurrent liabilities	1,545	1,358
Total other noncurrent liabilities	458,600	310,935
Commitments and contingencies (Note 7)		
Shareholders equity:		
Preferred stock, $0.01 par value: 25,000,000 shares authorized; no shares issued and outstanding		
Common stock, $0.01 par value; 500,000,000 shares authorized, 169,223,802 shares issued and outstanding at September 30, 2008; 168,864,015 shares issued and outstanding at December 31, 2007	1,692	1,689
Additional paid-in-capital	422,970	415,435
Retained earnings	526,542	206,008
Total shareholders equity	951,204	623,132

Total liabilities and shareholders equity	$	2,106,677	$	1,365,173

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

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Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Operations

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands, except per share data)		(In thousands, except per share data)	
Revenues:				
Oil and natural gas sales	$ 266,544	$ 159,987	$ 753,554	$ 400,781
Oil and natural gas sales to affiliates	19,650	6,717	55,684	21,953
Loss on mark-to-market derivative instruments		(14,393)	(7,966)	(14,393)
Oil and natural gas service operations	7,415	4,461	23,422	14,880
Total revenues	293,609	156,772	824,694	423,221
Operating costs and expenses:				
Production expenses	18,886	16,014	60,704	44,629
Production expense to affiliates	6,361	4,547	14,569	13,572
Production tax	17,941	8,711	48,411	22,311
Exploration expense	15,285	2,758	26,278	6,664
Oil and natural gas service operations	5,099	2,414	15,797	8,767
Depreciation, depletion, amortization and accretion	39,120	23,568	95,828	67,306
Property impairments	9,947	4,099	17,620	12,992
General and administrative	10,005	6,231	27,812	27,654
(Gain) loss on sale of assets	(194)	62	(406)	(338)
Total operating costs and expenses	122,450	68,404	306,613	203,557
Income from operations	171,159	88,368	518,081	219,664
Other income (expense):				
Interest expense	(2,506)	(2,774)	(8,782)	(9,854)
Other	185	318	732	1,207
	(2,321)	(2,456)	(8,050)	(8,647)
Income before income taxes	168,838	85,912	510,031	211,017
Provision for income taxes	63,582	29,540	189,497	243,329
Net income (loss)	$ 105,256	$ 56,372	$ 320,534	$ (32,312)
Basic net income (loss) per share	$ 0.63	$ 0.34	$ 1.91	$ (0.20)
Diluted net income (loss) per share	$ 0.62	$ 0.33	$ 1.89	$ (0.20)
Dividends per share				0.33
Pro forma (unaudited):				
Income before income taxes				$ 211,017
Provision for income taxes				80,186
Net income				$ 130,831
Basic net income per share				$ 0.80
Diluted net income per share				$ 0.80

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

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Continental Resources, Inc. and Subsidiary

Condensed Consolidated Statements of Shareholders Equity

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income (loss)	Total shareholders equity
			(in thousands, except share data)			
Balance, January 1, 2007	159,106,244	$ 144	$ 27,087	$ 463,255	$ (25)	$ 490,461
Comprehensive income:						
Net income				28,580		28,580
Other comprehensive income, net of tax					25	25
Total comprehensive income						28,605
Public offering of common stock	8,850,000	89	124,406			124,495
Reclass for stock split		1,447	(1,447)			
Adjust for undistributed earnings from conversion to subchapter C corporation			234,099	(234,099)		
Reclass stock compensation liability to equity			29,828			29,828
Stock-based compensation			3,874			3,874
Tax benefit on share-based compensation plan			1,630			1,630
Stock options:						
Exercised	689,476	7	619			626
Repurchased and canceled	(292,313)	(3)	(3,079)			(3,082)
Restricted stock:						
Issued	629,684	6				6
Repurchased and canceled	(77,441)	(1)	(1,476)			(1,477)
Forfeited	(41,635)		(106)			(106)
Dividends				(51,728)		(51,728)
Balance, December 31, 2007	168,864,015	$ 1,689	$ 415,435	$ 206,008	$	$ 623,132
Net income (unaudited)				320,534		320,534
Stock-based compensation (unaudited)			7,328			7,328
Tax benefit on share-based compensation plan (unaudited)			3,393			3,393
Stock options:						
Exercised (unaudited)	319,647	3	1,158			1,161
Repurchased and canceled (unaudited)	(74,179)		(3,853)			(3,853)
Restricted stock:						
Issued (unaudited)	149,149					
Repurchased and canceled (unaudited)	(11,080)		(491)			(491)
Forfeited (unaudited)	(23,750)					
Balance, September 30, 2008 (unaudited)	169,223,802	$ 1,692	$ 422,970	$ 526,542	$	$ 951,204

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

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Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Cash Flows

	Nine months ended September 30, 2008	2007
Cash flows from operating activities:		(In thousands)
Net income (loss)	$ 320,534	$ (32,312)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	95,946	68,124
Property impairments	17,620	12,992
Change in derivative fair value	(26,703)	12,542
Equity compensation	6,479	12,097
Tax benefit of excess non qualified stock compensation deduction	(3,393)	
Provision for deferred income taxes	151,852	243,329
Dry hole costs	9,399	2,293
Other, net	174	149
Changes in assets and liabilities:		
Accounts receivable	(136,674)	(55,806)
Inventories	(14,899)	(5,288)
Prepaid expenses and other	2,097	(6,654)
Accounts payable	108,612	(1,664)
Revenues and royalties payable	36,624	24,637
Accrued liabilities and other	22,076	3,579
Other noncurrent liabilities	188	338
Net cash provided by operating activities	589,932	278,356
Cash flows from investing activities:		
Exploration and development	(574,156)	(366,013)
Purchase of oil and gas properties	(74,514)	(146)
Purchase of other property and equipment	(13,638)	(3,865)
Proceeds from sale of assets	2,192	2,091
Net cash used in investing activities	(660,116)	(367,933)
Cash flows from financing activities:		
Credit facility	268,000	239,500
Repayment of credit facility	(203,600)	(223,000)
Proceeds from initial public offering, net		124,495
Dividends to shareholders	(9)	(51,835)
Repurchase of equity grants	(4,344)	(1,336)
Exercise of options	1,161	103
Tax benefit of excess non qualified stock compensation deduction	3,393	
Debt issuance costs	(45)	(45)
Net cash provided by financing activities	64,556	87,882
Effect of exchange rate changes on cash and cash equivalents		160
Net change in cash and cash equivalents	(5,628)	(1,535)
Cash and cash equivalents at beginning of period	8,761	7,018
Cash and cash equivalents at end of period	$ 3,133	$ 5,483

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

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Continental Resources, Inc. and Subsidiary

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Business

Description of Company

Continental Resources, Inc. s (Continental or the Company) principal business is oil and natural gas exploration, development and production. Continental s operations are primarily in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

The accompanying condensed consolidated balance sheet as of December 31, 2007, which has been derived from audited financial statements, and the unaudited condensed consolidated financial statements of Continental as of September 30, 2008 and for the interim periods ended September 30, 2008 and 2007 have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial statements. All significant intercompany accounts and transactions have been eliminated in the condensed consolidated financial statements.

The preparation of these interim financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The most significant of the estimates and assumptions that affect reported results is the estimate of the Company s oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing oil and gas properties. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with accounting principles generally accepted in the United States of America have been included in these unaudited interim condensed consolidated financial statements. The results of operations for any interim period are not necessarily indicative of the results of operations for the entire year. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes for the year ended December 31, 2007.

Pro forma information (unaudited)

Pro forma adjustments are reflected on the condensed consolidated statements of operations to provide for income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109*, Accounting for Income Taxes*, as if the Company had been a subchapter C corporation for the nine months ended September 30, 2008. For unaudited pro forma income tax calculations, deferred tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities were measured using enacted tax rates expected to apply to taxable income in the years in which the Company expects to recover or settle those temporary differences. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for 2007. The pro forma tax adjustments are to provide for income taxes as if the Company had been a subchapter C corporation prior to the completion of its public offering in May 2007. Management believes that these assumptions provide a reasonable basis for representing the pro forma tax effects.

Net Income Per Common Share

Basic net income (loss) per common share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted net income (loss) per share reflects the potential dilution of non-vested restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if these options were exercised. Potentially dilutive non-vested restricted shares and stock options were not considered in the calculation of the diluted weighted average shares outstanding used in computing diluted net income per share for the nine months ended September 30, 2007, because the effect was anti-dilutive. The following table sets forth the computation of basic and diluted weighted shares used in the basic and diluted net income per share computations for the three and nine months ended September 30, 2008 and 2007.

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	Three months ended September 30, 2008	2007	Nine months ended September 30, 2008	2007
	(in thousands, except per share data)			
Income (numerator):				
Net income (loss) - basic and diluted	$ 105,256	$ 56,372	$ 320,534	$ (32,312)
Weighted average shares (denominator):				
Weighted average shares - basic	168,097	167,232	168,008	162,869
Dilution effect of unvested restricted shares and stock options outstanding at end of period	1,429	1,811	1,469	
Weighted average shares - diluted	169,526	169,043	169,477	162,869
Net income (loss) per share:				
Basic	$ 0.63	$ 0.34	$ 1.91	$ (0.20)
Diluted	$ 0.62	$ 0.33	$ 1.89	$ (0.20)

Pro forma weighted average shares of 164,546,000 were used in the calculation of pro forma diluted net income per share for the nine months ended September 30, 2007.

Recent Accounting Pronouncements

In February 2008, the FASB issued FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157,* which provides a one year delay of the effective date of FAS 157 to January 1, 2009 for the Company for non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The impact of adoption related to the non-financial assets and liabilities will depend on the Company s assets and liabilities at the time they are required to be measured at fair value.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51* (SFAS 160). SFAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS 160 will change the accounting and reporting for minority interests, which will be re-characterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for the Company for fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. Early adoption is prohibited for both standards. The adoption of SFAS 141(R) and SFAS 160 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133,* which amends and expands the disclosure requirements of FAS 133 to require qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement will be effective for the Company beginning in fiscal 2009. The adoption of this statement will change the disclosures related to derivative instruments held by the Company, if any.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS No. 162 is effective sixty days following the SEC s approval of PCAOB amendments to AU Section 411, *The Meaning of Present fairly in conformity with generally accepted accounting principles* . SFAS 162 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

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Note 3. Cash Flow Information

Net cash provided by operating activities reflects cash interest payments of $8.2 million and $8.7 million for the nine months ended September 30, 2008 and 2007, respectively. Non-cash investing activities consisting of additions to the asset retirement obligations were $3.5 million and $1.7 million for the nine months ended September 30, 2008 and 2007, respectively. The Company paid cash income taxes of $30.8 million and $6.9 million during the nine months ended September 30, 2008 and 2007, respectively.

Note 4. Derivatives

In July 2007, the Company entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, the Company received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company elected not to designate its derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, the Company marked its derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value on derivative instruments in the statements of operations. As of September 30, 2008 the Company had no open derivative positions.

Note 5. Long-term Debt

The Company had $229.4 million and $165.0 million in long-term debt outstanding as of September 30, 2008 and December 31, 2007, respectively, on its credit facility.

The credit facility matures on April 12, 2011. At the Company s election, the maturity date can be extended for up to two one-year periods. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months, as elected by the Company, plus a margin ranging from 100 to 175 basis points, depending on the percentage of its borrowing base utilized, or the lead bank s reference rate. The credit facility has a maximum facility amount of $750.0 million, a borrowing base of $1.0 billion, subject to semi-annual re-determination, and a commitment level of $400.0 million. Under the terms of the credit facility, the Company is allowed to set the commitment level up to the lesser of the borrowing base or the maximum facility amount. While the borrowing base is set at $1.0 billion by the banks based on their valuation of the underlying reserves, the Company could not borrow more than the maximum facility amount of $750.0 million without amending the agreement. The Company s weighted average interest rate was 3.99% at September 30, 2008.

The Company had $170.6 million of unused commitments under the Credit Agreement at September 30, 2008 and incurs commitment fees of 0.2% of the daily average excess of the commitment amount over the outstanding credit balance. The credit facility contains certain covenants including that the Company maintain a current ratio of not less than 1.0 to 1.0 (inclusive of availability under the Credit Agreement) and a Total Funded Debt to EBITDAX, as defined, of no greater than 3.75 to 1.0 on a rolling four-quarter basis. The Company was in compliance with these covenants at September 30, 2008.

Note 6. Income Taxes

The following is an analysis of the Company s consolidated income tax provision for the periods indicated. The Company converted to a subchapter C corporation on May 14, 2007. Prior to this date, the Company was a subchapter S corporation and income taxes were payable by its shareholders.

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Current:				
Federal	$ 11,207	$	$ 33,528	$
State	1,334		4,117	
Total current tax provision	12,541		37,645	
Deferred:				

Federal	45,611	32,356	135,812	217,443
State	5,430	(2,816)	16,040	25,886
Total deferred tax provision	51,041	29,540	151,852	243,329
Income tax provision	$ 63,582	$ 29,540	$ 189,497	$ 243,329

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The following table reconciles the income tax provision with income tax at the Federal statutory rate for the periods indicated:

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(in thousands)			
Federal tax at statutory rate	$ 59,092	$ 30,069	$ 178,510	$ 73,856
State income taxes, net of federal benefit	4,390	2,234	13,261	5,486
Eliminate taxes on earnings prior to subchapter C corporation conversion [(1)]				(32,380)
Non-deductible stock-based compensation		564	15	878
Excess statutory depletion	(325)		(1,378)	
Domestic production activities deduction	(617)		(2,604)	
Other, net	1,042	(308)	1,693	104
Earnings transferred to subchapter S corporation through election of pro-rata allocation method [(2)]		(3,019)		(3,019)
Deferred taxes recorded upon conversion to a subchapter C corporation				198,404
Income tax provision	$ 63,582	$ 29,540	$ 189,497	$ 243,329

(1) Federal tax at statutory rate and state income taxes have been calculated based upon the full net income before tax for the period. However, the Company converted from a subchapter S corporation to a subchapter C corporation on May 14, 2007. This line item eliminates the tax effect related to the net income before tax from the beginning of the period presented through the date of conversion to a subchapter C corporation, which tax effects are already included in the line item deferred taxes recorded upon conversion to a subchapter C corporation.

(2) During the third quarter of 2007, the Company changed its estimate of income allocation to the subchapter S corporation period assuming the use of the pro-rata income allocation method for tax purposes instead of the specific identification method used for tax and financial reporting purposes at June 30, 2007. Assuming income is allocated using the pro-rata income allocation method, the Company s income for the year is allocated to the subchapter S corporation and the subchapter C corporation based on number of days without regard to when the income was actually earned. The net effect of this change in estimate was a benefit of $3.0 million.

Significant components of the Company s deferred tax assets and liabilities as of September 30, 2008 and December 31, 2007 are as follows:

	September 30, 2008	December 31, 2007
	(in thousands)	
Current:		
Deferred tax assets [(1)]		
Unrealized losses on derivatives	$	$ 10,040
Other expenses	690	602
Total current deferred tax assets	690	10,642
Noncurrent:		
Deferred tax assets		
Net operating loss carryforward		4,553
Alternative minimum tax carryforward		6,537
Deferred compensation	5,453	1,952
Other	361	438
Total noncurrent deferred tax assets	5,814	13,480
Deferred tax liabilities		
Property and equipment	421,220	284,904
Net noncurrent deferred tax liabilities	415,406	271,424

Net deferred tax liabilities	$ 414,716	$ 260,782

(1) Deferred and prepaid taxes on the consolidated balance sheets at December 31, 2007 contain prepaid taxes of $1.2 million.

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Note 7. Commitments and Contingencies

The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will have a material adverse effect on the financial position or results of operations of the Company. As of September 30, 2008 and December 31, 2007, the Company has provided a reserve of $1.2 million and $1.0 million, respectively, for various matters none of which are believed to be individually significant. Due to the nature of the oil and gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

Note 8. Stock Compensation

Effective October 1, 2000, the Company adopted the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and granted options to certain eligible employees. These options were Incentive Stock Options, Nonqualified Stock Options or a combination of both. The granted stock options vest ratably over either a three or five year period commencing on the first anniversary of the grant date and expire ten years from date of grant. On November 10, 2005, the 2000 Plan was terminated.

The Company s outstanding stock option grants under the 2000 Plan are as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding December 31, 2007	886,527	$ 2.28	794,853	$ 1.88
Exercised	(319,647)	3.63		
Outstanding September 30, 2008	566,880	$ 1.51	566,880	$ 1.51

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option. The total intrinsic value of options exercised during the nine months ended September 30, 2008 was approximately $12.9 million. At September 30, 2008, the exercisable options had a weighted average life of 3.96 years and an aggregate intrinsic value of $21.4 million. As of September 30, 2008, all stock options were vested.

Restricted Stock

On October 3, 2005, the Company adopted the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) and reserved a maximum of 5,500,000 shares of non-voting common stock that may be issued pursuant to the 2005 Plan. As of September 30, 2008, the Company had 3,819,832 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends which is subject to forfeiture. Restricted stock grants vest over periods ranging from one to three years.

The Company began issuing shares of restricted common stock to employees and non-employee directors in October 2005. A summary of the status of the unvested shares of restricted stock as of September 30, 2008, and changes during the nine months ended September 30, 2008, is presented below:

	Unvested restricted shares	Weighted average grant-date fair value
Unvested restricted shares at January 1, 2008	1,047,706	$ 18.36
Granted	149,149	36.42
Vested	(48,300)	11.96
Forfeited	(23,750)	26.04
Outstanding September 30, 2008	1,124,805	$ 20.87

The fair value of the restricted shares that vested during the nine months ended September 30, 2008 at their vesting dates was $1.9 million. As of September 30, 2008, there was $12.0 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.40 years.

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Note 9. Fair Value Measures

The Company adopted SFAS No. 157, Fair Value Measurements, 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 FASB Staff Position FAS 157-2, which delayed the effective date of SFAS No. 157 by one year for non-financial 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. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps.

Level 3: Measures 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).

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. Our 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.

During the nine months ended September 30, 2008, the Company valued its derivative instruments according to SFAS No. 157 pricing levels. These contracts expired during the second quarter of 2008 and we currently do not have any financial assets or financial liabilities that are measured on a fair value basis.

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

The following discussion and analysis should be read in conjunction with our historical consolidated financial statements and the notes included in our Annual Report on Form 10-K for the year ended December 31, 2007. Our operating results for the periods discussed may not be indicative of future performance. Statements concerning future results are forward-looking statements. In the text below, financial statement numbers have been rounded; however, the percentage changes are based on amounts that have not been rounded.

Overview

Continental Resources, Inc. is an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We target large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations.

We principally derive our operating income and cash flow from the sale of oil and natural gas. We expect that growth in our operating income and revenues will primarily depend on our ability to increase our oil and natural gas production and on product prices. In recent months and years, there has been significant volatility in oil and natural gas prices due to a variety of factors we can not control or predict. These factors, which include weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for oil and natural gas, which affects prices. In addition, the prices we realize for our oil and natural gas production are affected by location differences in market prices.

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For the first nine months of 2008, our oil and gas production increased to 8,693 MBoe (31,725 Boe per day), up 11% from the first nine months of 2007. The increase in 2008 production primarily resulted from an increase in production from our Red River units, Bakken field and Arkoma Woodford shale play. Oil and natural gas revenues for the first nine months of 2008 increased by 91% to $809.2 million due to a 69% increase in price and a 13% increase in sales volumes. Our realized price per Boe increased $37.96 to $92.64 for the first nine months of 2008 compared to the first nine months of 2007. Production expense and production tax increased a combined $43.2 million, or 54%, and the combined per unit cost increased $3.74 per Boe, or 36%, due to expanded operations, increased workover activity in 2008 and higher production taxes which are generally a function of oil and gas revenue. Oil sales volumes were 42 MBbls more than oil production for the first nine months of 2008 and 96 MBbls less for the same period in 2007 due to fluctuations in pipeline linefill and temporarily stored barrels. Our cash flow from operating activities for the nine months ended September 30, 2008, was $589.9 million, an increase of $311.5 million from the comparable 2007 period. The increase in operating cash flows was mainly due to increases in revenue reflecting increased production volumes and product prices partially offset by higher operating costs. During the nine months ended September 30, 2008, we invested $654.3 million (inclusive of non-cash accruals of $66.5 million and exclusive of acquisition expenditures of $74.5 million) in our capital program primarily in the North Dakota Bakken field and the Red River Units in the Rocky Mountain region and the Arkoma Woodford shale play in the Mid-Continent region.

How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance. Among these measures are (1) volumes of oil and natural gas produced, (2) oil and natural gas prices realized, (3) per unit operating and administrative costs and (4) EBITDAX. The following table contains unaudited financial and operational highlights for the periods indicated.

	Three months ended September 30,		Nine Months ended September 30,	
	2008	2007	2008	2007
Average daily production:				
Oil (Bopd)	24,937	24,224	24,368	23,672
Natural gas (Mcfd)	50,156	31,499	44,139	29,994
Oil equivalents (Boepd)	33,297	29,474	31,725	28,671
Average prices: (1)				
Oil ($/Bbl)	$ 108.37	$ 69.44	$ 105.78	$ 58.92
Natural gas ($/Mcf)	7.97	5.29	8.14	5.82
Oil equivalents ($/Boe)	93.21	62.61	92.64	54.68
Production expense ($/Boe) (1)	8.22	7.72	8.62	7.53
General and administrative expense ($/Boe) (1)	3.26	2.34	3.18	3.58
EBITDAX (in thousands) (2)	238,289	132,817	665,027	332,472
Net income (loss) (in thousands) (3)	105,256	56,372	320,534	(32,312)
Diluted net income (loss) per share	0.62	0.33	1.89	(0.20)
Pro forma net income (in thousands) (4)				130,831
Pro forma diluted net income per share (4)				0.80

(1) Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions. Oil sales volumes were 7 MBbls more than oil production for the three months ended September 30, 2008 and 49 MBbls less than oil production for the three months ended September 30, 2007. For the nine months ended September 30, 2008 oil sales volumes were 42 MBbls more than oil production and 96 MBbls less than oil production for the nine months ended September 30, 2007.

(2) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains and losses and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). A reconciliation of net income to EBITDAX is provided in Managements Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures.

(3) Prior to the public offering, we were a subchapter S corporation and income taxes were payable by our shareholders. In connection with the public offering, we converted to a subchapter C corporation and recorded a charge to earnings in the second quarter of 2007 of $198.4 million to recognize deferred taxes relating to the timing differences that existed at May 14, 2007, the date we converted to a subchapter C corporation.

(4) Pro forma adjustments are reflected to provide for income taxes in accordance with SFAS No. 109 as if we had been a subchapter C corporation for the nine months ended September 30, 2007. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for 2007.

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

Results of Operations

The following table presents selected financial and operating information for each of the periods indicated below:

(in thousands, except price data)	Three months ended September 30, 2008	2007
Oil and natural gas sales	$ 286,194	$ 166,704
Derivatives		(14,393)
Total revenues	293,609	156,772
Operating costs and expenses	122,450	68,404
Other expense	2,321	2,456
Net income, before income taxes	168,838	85,912
Provision for income taxes	63,582	29,540
Net income (loss)	$ 105,256	$ 56,372
Production Volumes:		
Oil (MBbl)	2,294	2,229
Natural gas (MMcf)	4,614	2,898
Oil equivalents (MBoe)	3,063	2,712
Sales Volumes:		
Oil (MBbl)	2,301	2,180
Natural gas (MMcf)	4,614	2,898
Oil equivalents (MBoe)	3,070	2,663
Average Prices: [1]		
Oil ($/Bbl)	$ 108.37	$ 69.44
Natural gas ($/Mcf)	$ 7.97	$ 5.29
Oil equivalents ($/Boe)	$ 93.21	$ 62.61

(1) Average prices have been calculated using sales volumes and excluding any effect of derivative transactions.

Production

The following tables reflect our production by product and region for the periods presented.

	Three months ended September 30, 2008 Volume	Percent	2007 Volume	Percent	Volume Increase	Percent Increase
Oil (MBbl)	2,294	75%	2,229	82%	65	3%
Natural Gas (MMcf)	4,614	25%	2,898	18%	1,716	59%
Total (MBoe)	3,063	100%	2,712	100%	351	13%

	Three months ended September 30, 2008 MBoe	Percent	2007 MBoe	Percent	Volume Increase	Percent Increase
Rocky Mountain	2,326	76%	2,219	82%	107	5%
Mid-Continent	692	23%	451	17%	241	53%
Gulf Coast	45	1%	42	1%	3	7%

Total (MBoe)	3,063	100%	2,712	100%	351	13%

Oil production volumes increased 3% during the three months ended September 30, 2008 in comparison to the three months ended September 30, 2007. Production increases in the Rockies Other area contributed incremental volumes in excess of 2007 levels of 54 MBbls primarily as a result of acquisitions and the Mid-Continent area contributed 49 MBbls of incremental production. These increases and increases in the North Dakota Bakken area were largely offset by decreases in production in the Montana Bakken area of 113 MBbls as a result of natural declines. The Red River Units production decreased 89 MBbls due to the early-stage implementation of the Company s secondary water flood recovery program and conversion of producer wells to injection wells. Gas volumes increased 1,716 MMcf, or 59% during the three months ended September 30, 2008 compared to the same time period in 2007. The majority of the gas increase, 904 MMcf, was from the results of our exploration efforts and successful drilling in the Arkoma Woodford shale play. The Rocky Mountain region gas production was up 562 MMcf for the three months ended September 30, 2008 compared to the same time period in 2007 due to additional gas being sold through the Hiland Partners Badlands plant which became operational in late August 2007.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the three months ended September 30, 2008 were $286.2 million, a 72% increase from sales of $166.7 million for the comparable period in 2007. Our sales volumes increased 407 MBoe or 15% over the 2007 volumes due to the continuing success of our enhanced oil recovery and drilling programs and acquisitions. Our realized price per Boe increased 49%, or $30.60 to $93.21 for the three months ended September 30, 2008 from $62.61 for the three months ended September 30, 2007. The differential per barrel for the three months ended September 30, 2008 was $9.68 compared to $5.88 for the comparable period in 2007. Crude oil differentials widened significantly in the third quarter of 2008 in the Rockies area due to regional pipeline constraints and price seasonality.

NYMEX oil and natural gas prices peaked in July 2008 then began a steep decline which resulted in our average price for the third quarter of 2008 of $108.37 per barrel and $7.97 per Mcf, respectively. Our average oil and natural gas price for the second quarter of 2008 was $118.28 per barrel and $8.82 per Mcf, respectively. Prices have continued to drop since the end of the quarter and during the last week of October 2008 NYMEX oil prices were trading in the $60.00 to $70.00 per barrel range while natural gas prices were trading in the $6.00 to $7.00 per Mcf range. Oil and natural gas prices remain volatile and we are unable to predict when with any certainty future price fluctuations.

Derivatives. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil future contract settlement prices for such month. Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of operations. These contracts expired April 2008.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of reclaimed oil increased to $7.4 million for the three months ended September 30, 2008 from $4.4 million for the comparable period in 2007. We sold high-pressure air from our Red River units to a third party and recorded revenues of $0.8 million for the three months ended September 30, 2008 and 2007. Prices for reclaimed oil sold from our central treating unit of $106.36 per barrel for the three months ended September 30, 2008 were $40.71 per barrel higher than the comparable 2007 period which increased reclaimed oil income by $2.6 million contributing to an overall increase in oil and gas service operations revenue of $3.0 million for the three months ended September 30, 2008. Associated oil and natural gas service operations expenses increased $2.7 million to $5.1 million during the three months ended September 30, 2008 due mainly to an increase of $38.58 per barrel to $104.33 per barrel in the costs of purchasing and treating oil for resale compared to the same period in 2007.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $4.7 million, or 23% during the three months ended September 30, 2008 to $25.2 million from $20.6 million during the three months ended September 30, 2007. Our costs increased as a result of new wells being drilled coupled with workovers and repairs on existing wells and acquisitions. Our workover activity is typically higher in the summer months as weather conditions in the northern Rockies moderate. Additionally, we have experienced increases in energy, chemical and service costs. During the three months ended September 30, 2008, we participated in the completion of 74 gross (33.1 net) wells. Production expense per Boe increased to $8.22 per Boe for the three months ended September 30, 2008 from $7.72 per Boe for the three months ended September 30, 2007.

Production taxes increased $9.2 million, or 106% during the three months ended September 30, 2008 compared to the three months ended September 30, 2007 as a result of higher revenues from increased sales prices and volumes and the

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expiration of various tax incentives. The majority of the production tax increase was in the Mid-Continent region due to significantly higher oil and natural gas prices and an increase of 241 MBoe sold in the three months ended September 30, 2008 compared to the three months ended September 30, 2007. Production tax as a percentage of oil and natural gas sales was 6.27% for the three months ended September 30, 2008 compared to 5.23% for the three months ended September 30, 2007. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, North Dakota and Oklahoma new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rates. Our overall rate is expected to increase as production tax incentives we currently receive for horizontal wells reach the end of their incentive period.

On a unit of sales basis, production expense and production taxes were as follows:

($/Boe)	Three months ended September 30, 2008	Three months ended September 30, 2007	Percent Increase
Production expense	$ 8.22	$ 7.72	6%
Production tax	5.84	3.27	79%
Production expense and tax	$ 14.06	$ 10.99	28%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $12.5 million during the three months ended September 30, 2008 to $15.3 million due primarily to an increase in dry hole expense of $6.7 million and seismic expense of $5.5 million.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A increased $15.6 million in 2008 primarily due to an increase in oil and gas DD&A of $15.2 million as a result of increased production and additional properties being added through our drilling program and acquisitions. The following table shows the components of our DD&A rate for the three months ended September 30, 2008 and 2007.

($/Boe)	Three months ended September 30, 2008	Three months ended September 30, 2007
Oil and gas	$ 12.30	$ 8.48
Other equipment	0.27	0.19
Asset retirement obligation accretion	0.17	0.19
Depreciation, depletion, amortization and accretion	$ 12.74	$ 8.86

The increase in the oil and gas DD&A rate reflects the additional costs incurred to develop proved undeveloped reserves and the higher cost of drilling and completing wells. Our DD&A rate may continue to increase due to drilling for higher cost reserves.

Property Impairments. Property impairments increased during the three months ended September 30, 2008 by $5.8 million to $9.9 million compared to the three months ended September 30, 2007. The increase was primarily due to an increase in impairment of developed properties of $5.9 million to $7.0 million. Impairment of non-producing properties decreased $0.1 million during the three months ended September 30, 2008 to $2.9 million. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimate of successful drilling and the average holding period.

General and Administrative Expense. General and administrative expense increased $3.8 million to $10.0 million during the three months ended September 30, 2008. General and administrative expense includes non-cash charges for stock-based compensation of $2.6 million for the three months ended September 30, 2008 and $1.2 million for the three months ended September 30, 2007. General and administrative expenses excluding equity compensation increased $2.3 million for the three months ended September 30, 2008 compared to the three months ended September 30, 2007. The increase was primarily related to personnel costs. On a volumetric basis, general and administrative expense was $3.26 per Boe for the three months ended September 30, 2008 compared to $2.34 per Boe for the three months ended September 30, 2007.

Interest Expense. Interest expense decreased 10%, or $0.3 million for the three months ended September 30, 2008 compared to the three months ended September 30, 2007, due to a lower weighted average interest rate on our credit facility of 3.94% for the three months ended September 30, 2008 compared to 6.52% for the three months ended September 30, 2007. Our weighted average interest rate has fallen in 2008 as LIBOR rates have declined. Our average outstanding debt

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balance on our credit facility increased to $233.7 million for the three months ended September 30, 2008 compared to $154.1 million for the three months ended September 30, 2007. At October 31, 2008, our outstanding balance was $276.4 million and our weighted average interest rate was 4.32%.

Income Taxes. Income taxes for the three months ended September 30, 2008 and 2007 were $63.6 million and $29.5 million, respectively, resulting in an effective tax rate of 37.7% and 34.4%, respectively. See *Note 6. Income Taxes* in Notes to Unaudited Condensed Consolidated Financial Statements for more information.

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

Results of Operations

The following table presents selected financial and operating information for each of the periods indicated below:

	Nine months ended September 30,	
(in thousands, except price data)	**2008**	**2007**
Oil and natural gas sales	$ 809,238	$ 422,734
Derivatives	(7,966)	(14,393)
Total revenues	824,694	423,221
Operating costs and expenses	306,613	203,557
Other expense	8,050	8,647
Net income, before income taxes	510,031	211,017
Provision for income taxes	189,497	243,329
Net income (loss)	$ 320,534	$ (32,312)
Production Volumes:		
Oil (MBbl)	6,677	6,462
Natural gas (MMcf)	12,094	8,188
Oil equivalents (MBoe)	8,693	7,827
Sales Volumes:		
Oil (MBbl)	6,719	6,366
Natural gas (MMcf)	12,094	8,188
Oil equivalents (MBoe)	8,735	7,731
Average Prices: (1)		
Oil ($/Bbl)	$ 105.78	$ 58.92
Natural gas ($/Mcf)	$ 8.14	$ 5.82
Oil equivalents ($/Boe)	$ 92.64	$ 54.68

(1) Average prices have been calculated using sales volumes and excluding any effect of derivative transactions.

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Production

The following tables reflect our production by product and region for the periods presented.

	Nine months ended September 30,					
	2008		2007		Volume	Percent
	Volume	Percent	Volume	Percent	Increase	Increase
Oil (MBbl)	6,677	77%	6,462	83%	215	3%
Natural Gas (MMcf)	12,094	23%	8,188	17%	3,906	48%
Total (MBoe)	8,693	100%	7,827	100%	866	11%

	Nine months ended September 30,					
	2008		2007		Volume	Percent
	MBoe	Percent	MBoe	Percent	Increase	Increase
Rocky Mountain	6,728	77%	6,356	81%	372	6%
Mid-Continent	1,809	21%	1,324	17%	485	37%
Gulf Coast	156	2%	147	2%	9	6%
Total (MBoe)	8,693	100%	7,827	100%	866	11%

Oil production volumes increased 3% during the nine months ended September 30, 2008 in comparison to the nine months ended September 30, 2007. Production increases in the Rockies Other and Mid-Continent areas contributed incremental volumes in excess of 2007 levels of 159 MBbls and 69 MBbls of incremental production, respectively. Favorable results from drilling and acquisitions have been the primary contributors to production growth in these areas. Gas volumes increased 3.9 Bcf, or 48% during the nine months ended September 30, 2008 compared to the same time period in 2007. The majority of the gas increase, 2.5 Bcf, was from the Mid-Continent region due to the results of our exploration efforts and successful drilling in the Arkoma Woodford shale play. The Rocky Mountain region gas production was up 1.5 Bcf for the nine months ended September 30, 2008 compared to the same time period in 2007 due to additional gas being sold through the Hiland Partners Badlands plant which became operational in late August 2007. Since that time, we have sold 2.1 Bcf of gas from the Red River units through the Badlands plant.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the nine months ended September 30, 2008 were $809.2 million, a 91% increase from sales of $422.7 million for the comparable period in 2007. Our sales volumes increased 1,004 MBoe or 13% over the 2007 volumes due to the continuing success of our enhanced oil recovery and drilling programs and acquisitions. Our realized price per Boe increased 69%, or $37.96, to $92.64 for the nine months ended September 30, 2008 from $54.68 for the nine months ended September 30, 2007. During 2008, the differential between NYMEX calendar month average crude oil prices and our realized crude oil prices narrowed. The differential per barrel for the nine months ended September 30, 2008 was $7.64 compared to $7.46 for the comparable period in 2007. Crude oil differentials have improved during 2008 due to enhanced transportation capacity and efforts by us to move crude oil to more favorable markets. Crude oil differentials widened significantly in the third quarter of 2008 in the Rockies area due to regional pipeline constraints and price seasonality.

Derivatives. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil future contract settlement prices for such month. Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of operations. These contracts expired in April 2008 and during the nine months ended September 30, 2008, we had recognized losses on derivatives of $8.0 million.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of reclaimed oil. We sold high-pressure air from our Red River units to a third party and recorded revenues of $2.2 million for the nine months ended September 30, 2008 and $2.4 million for the nine months ended September 30, 2007. Prices for reclaimed oil sold from our central treating unit for the nine months ended September

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30, 2008 of $104.71 per barrel were $49.24 per barrel higher than the comparable 2007 period which increased reclaimed oil income by $7.8 million contributing to an overall increase in oil and gas service operations revenue of $8.5 million for the nine months ended September 30, 2008. Associated oil and natural gas service operations expenses increased $7.0 million to $15.8 million during the nine months ended September 30, 2008 from $8.8 million during the nine months ended September 30, 2007 due mainly to an increase of $46.17 per barrel to $101.73 per barrel in the costs of purchasing and treating oil for resale compared to the same period in 2007.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $17.1 million, or 29%, during the nine months ended September 30, 2008 to $75.3 million from $58.2 million during the nine months ended September 30, 2007. Our costs increased as a result of new wells being drilled coupled with workovers and repairs on existing wells and acquisitions. Additionally, we have experienced increases in energy, chemical and service costs. During the nine months ended September 30, 2008, we participated in the completion of 221 gross (99.5 net) wells. Production expense per Boe increased to $8.62 per Boe for the nine months ended September 30, 2008 from $7.53 per Boe for the nine months ended September 30, 2007.

Production taxes increased $26.1 million, or 117% during the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007 as a result of higher revenues from increased sales prices and volumes and the expiration of various tax incentives. The majority of the production tax increase was in the Mid-Continent region and the Rocky Mountain region due to an increase of 995 MBoe sold and significantly higher oil and natural gas prices in the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007. Production tax as a percentage of oil and natural gas sales was 5.98% for the nine months ended September 30, 2008 compared to 5.28% for the nine months ended September 30, 2007. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, North Dakota and Oklahoma new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rates. Our overall rate is expected to increase as production tax incentives we currently receive for horizontal wells reach the end of their incentive period.

On a unit of sales basis, production expense and production taxes were as follows:

	Nine months ended September 30,		
($/Boe)	**2008**	**2007**	**Percent Increase**
Production expense	$ 8.62	$ 7.53	14%
Production tax	5.54	2.89	92%
Production expense, tax and other	$ 14.16	$ 10.42	36%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $19.6 million during the nine months ended September 30, 2008 to $26.3 million due primarily to an increase in seismic expense of $11.8 million and an increase in dry hole expense of $7.1 million.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A increased $28.5 million in 2008 primarily due to an increase in oil and gas DD&A of $28.0 million as a result of increased production and additional properties being added through our drilling program and acquisitions. The following table shows the components of our DD&A rate.

	Nine months ended September 30,	
($/Boe)	**2008**	**2007**
Oil and gas	$ 10.57	$ 8.33
Other equipment	0.22	0.19
Asset retirement obligation accretion	0.17	0.19
Depreciation, depletion, amortization and accretion	$ 10.96	$ 8.71

The increase in the oil and gas DD&A rate reflects the additional costs incurred to develop proved undeveloped reserves and the higher cost of drilling and completing wells. Our DD&A rate may continue to increase due to drilling for higher cost reserves.

Property Impairments. Property impairments increased during the nine months ended September 30, 2008 by $4.6 million to $17.6 million primarily due to an increase in impairments of developed properties. Proved property impairments increased $4.9 million. Impairment of non-producing properties decreased $0.3 million during the nine months ended September 30, 2008 to $8.8 million. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimate of successful drilling and the average holding period.

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General and Administrative Expense. General and administrative expense increased $0.1 million to $27.8 million during the nine months ended September 30, 2008 from $27.7 million during the same period in 2007. General and administrative expense includes non-cash charges for stock-based compensation of $6.5 million and $12.1 million for the nine months ended September 30, 2008 and 2007, respectively. Stock compensation expense was higher in 2007 due to the increase in value of the stock as we approached our initial public offering. Until our initial public offering in May 2007, the outstanding options and restricted stock were accounted for as liability awards and their value fluctuated with the value of the underlying stock. General and administrative expenses excluding equity compensation increased $5.2 million for the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007. The increase was primarily related to a $4.4 million increase in personnel costs due to approximately 60 additional employees and higher wages and increased benefits. Also, in June 2008, the Company made a $1.0 million donation to take advantage of private and state matching funds that will result in a total donation of $4.0 million to support a petroleum engineering program at Oklahoma State University. On a volumetric basis, general and administrative expense decreased to $3.18 per Boe for the nine months ended September 30, 2008 compared to $3.58 per Boe for the nine months ended September 30, 2007.

Interest Expense. Interest expense decreased 11%, or $1.1 million, for the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007, due to a lower weighted average interest rate on our credit facility of 4.66% for the nine months ended September 30, 2008 compared to 6.53% for the nine months ended September 30, 2007. Our weighted average interest rate has fallen in 2008 as LIBOR rates have declined. Our average outstanding debt balance on our credit facility increased to $227.6 million for the nine months ended September 30, 2008 compared to $183.6 million for the nine months ended September 30, 2007. At October 31, 2008, our outstanding balance was $276.4 million and our weighted average interest was 4.32%.

Income Taxes. Income taxes for the nine months ended September 30, 2008 and 2007 were $189.5 million and $243.3 million, respectively, resulting in an effective tax rate of 37.2% and 115.3%, respectively. The 2007 tax rate reflects a charge to earnings of $198.4 million to recognize deferred taxes at May 14, 2007 when the Company converted from a subchapter S corporation to a subchapter C corporation in connection with its public offering. Thereafter, the Company has provided for income taxes on its income. See *Note 6. Income Taxes* in Notes to Unaudited Condensed Consolidated Financial Statements for more information.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facility. Recently oil and natural gas prices have declined significantly, reducing our cash flows. In response, we have begun reducing capital expenditures for the remainder of 2008 and have budgeted for 2009 assuming lower commodity prices. However, realigning capital expenditures to reflect lower cash flows is not an instantaneous process and we expect our debt will increase into 2009 as operating activities and expenses are matched with the reduced level of cash flow.

The turmoil in the equity and credit markets has not had an immediate impact on our sources of liquidity. However, if the unsettled conditions continue long term it may impact our ability to develop all of our projects. Our banks are currently evaluating our borrowing base in connection with our semi-annual borrowing base redetermination. While we are unable to predict with certainty our borrowing base, we believe that it will be sufficient to meet our financing needs. Our current facility is backed by a syndicate of 10 banks. We currently believe that all of the syndicate banks have the capability to fund up to our current commitment. If one or more should not be able to do so, we may not have the full availability of $400 million. If we were to increase our commitment, it is likely the additional funds would only be available at a higher premium to LIBOR than the rate under our existing facility based on the current financial markets.

We believe that funds from operating cash flows and the bank credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months.

We intend to fund our longer term cash requirements beyond 12 months through operating cash flows, commercial bank borrowings and access to equity and debt capital markets. Although our longer term needs may be impacted by factors such as proved reserve acquisitions, declines in oil and natural gas prices, drilling results, ability to obtain needed capital on satisfactory terms, turmoil in the equity and credit markets, and other risks which could negatively impact production and our results of operations, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements.

At September 30, 2008 and December 31, 2007, we had cash and cash equivalents of $3.1 million and $8.8 million, respectively. At September 30, 2008, our available borrowing capacity on our credit facility was $170.6 million. The amount borrowed under the credit facility at October 31, 2008 was $276.4 million and we have unused commitments of $123.6 million. During the second quarter of 2008, in connection with our semiannual borrowing base redetermination, our borrowing base was raised to $1.0 billion. Our commitment level remains at $400.0 million. While the borrowing base is set at $1.0 billion by our banks based on their valuation of the underlying reserves, we could not borrow more than the maximum facility amount of $750.0 million without amending the agreement.

Cash Flow From Operating Activities

Our net cash provided by our operating activities for the nine months ended September 30, 2008, was $589.9 million, an increase of $311.5 million from $278.4 million provided by our operating activities during the comparable 2007 period. The increase in operating cash flows was mainly due to increases in revenue reflecting increased production volumes and product prices partially offset by higher operating costs.

Cash Flow From Investing Activities

During the nine months ended September 30, 2008 and 2007 we had cash flows used in investing activities (excluding asset sales) of $662.3 million and $370.0 million, respectively in our capital program, inclusive of dry hole and seismic costs. The increase in our capital program was mainly due to increased drilling in our Rocky Mountain region and in our Arkoma Woodford shale play.

Cash Flow From Financing Activities

Net cash provided by financing activities of $64.6 million for the nine months ended September 30, 2008 was mainly the result of amounts borrowed under our credit facility to fund capital expenditures, including acquisitions. Net cash provided by financing activities was $87.9 million for the nine months ended September 30, 2007 and was mainly the result of proceeds of our initial public offering net of amounts used to pay cash dividends.

Capital Expenditures

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 acquisitions that utilize our technical expertise or offer opportunities to expand our existing core area. Acquisition expenditures are not budgeted. Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. During the first nine months of 2008, we participated in the completion of 211 gross (99.5 net) wells and invested a total of $654.3 million including $467.1 million in drilling and capital facilities and $173.6 million for undeveloped acreage. In addition, we have invested $74.5 million for acquisitions through September 30, 2008.

In April 2008, the Board of Directors approved an increase in our drilling, land and seismic capital expenditures budget from $616.0 million to $783.0 million. In July 2008, the Board of Directors increased the land budget by $100.0 million to $178.0 million, which increased the overall budget to $883.0 million.

As a result of lower commodity prices and the prospect of lower cash flows in 2009, Continental has set its 2009 capital expenditure budget at $609 million, with $541 million allocated primarily for drilling and completion operations. This compares with a revised 2008 capital expenditure budget of $883 million, with $663 million allocated primarily for drilling and completion operations. Our investment in land and seismic acquisition will be greatly reduced in 2009. The 2009 capital expenditures budget envisions an average of 15.5 operated rigs for the year, with eight operating in the North Dakota Bakken.

Although we can not 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, cash flows from operations and borrowings available under our credit facility will be sufficient to satisfy our 2008 and 2009 capital budget.

Recent Accounting Pronouncements

In February 2008, the FASB issued FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157,* which provides a one year delay of the effective date of FAS 157 to January 1, 2009 for us for non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The impact of adoption related to the non-financial assets and liabilities will depend on our assets and liabilities at the time they are required to be measured at fair value.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51* (SFAS 160). SFAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS 160 will change the accounting and reporting for minority interests, which will be re-characterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for our fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. Early adoption is prohibited for both standards. The adoption of SFAS 141(R) and SFAS 160 is not expected to have a material impact on our consolidated financial position or results of operations.

In March 2008, the FASB issued FAS 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133,* which amends and expands the disclosure requirements of FAS 133 to require qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement will be effective for us beginning in fiscal 2009. The adoption of this statement will change the disclosures related to derivative instruments held by us.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS No. 162 is effective sixty days following the SEC s approval of PCAOB amendments to AU Section 411, *The Meaning of Present fairly in conformity with generally accepted accounting principles* . SFAS 162 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

Contractual Commitments

There have been no material changes in our contractual obligations and commitments from those disclosed in our Form 10-K for the year ended December 31, 2007.

Critical Accounting Policies

There has been no change in our critical accounting policies from those disclosed in our Form 10-K for the year ended December 31, 2007.

Disclosure Regarding Forward-Looking Statements

This report includes forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond our control. All information, other than historical facts included in this report, regarding our strategy, future operations, drilling plans, estimated reserves, future production, estimated capital expenditures, projected costs, the potential of drilling prospects and other plans and objectives of management are forward-looking information. All forward-looking statements speak only as of the date of this report. Although we believe that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Actual results may differ materially from those anticipated due to many factors, including oil and natural gas prices, industry conditions, drilling results, uncertainties in estimating reserves, uncertainties in estimating future production from enhanced recovery operations, availability of drilling rigs and other services, availability of crude oil and natural gas transportation capacity, availability of capital resources and other factors listed in reports we have filed or may file with the Securities and Exchange Commission.

Non-GAAP Financial Measures

EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains and losses, and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by

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investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. The credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. The following table is a reconciliation of our net income to EBITDAX.

	Three months ended September 30, 2008	2007	Nine months ended September 30, 2008	2007
Net income (loss)	$ 105,256	$ 56,372	$ 320,534	$ (32,312)
Unrealized derivative loss		12,542		12,542
Interest expense	2,506	2,774	8,782	9,854
Provision for income taxes	63,582	29,540	189,497	243,329
Depreciation, depletion, amortization and accretion	39,120	23,568	95,828	67,306
Property impairments	9,947	4,099	17,620	12,992
Exploration expense	15,285	2,758	26,278	6,664
Equity compensation	2,593	1,164	6,488	12,097
EBITDAX	$ 238,289	$ 132,817	$ 665,027	$ 332,472

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

General

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

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and gas production, which we market to energy marketing companies, refineries and affiliates. 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 credit worthiness. We have not generally required our counterparties to provide collateral to support oil and natural gas sales receivables. We generally do not receive any collateral from our working interest owners on the joint interest receivables other than contractually provided lein rights. However, we routinely require prepayment of working interest holders proportionate share of drilling costs. A liability is recorded for such prepayments and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk.

Commodity Price Risk. Our primary market risk exposure is in the pricing applicable to our natural gas and oil production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control including volatility in the differences between product prices at sales points and the applicable index price. Based on our average daily production for the nine months ended September 30, 2008, our annual revenue would increase or decrease by approximately $8.9 million for each $1.00 per barrel change in crude oil prices and $1.6 million for each $0.10 decrease per MMBtu in natural gas prices.

To partially reduce price risk caused by these market fluctuations, we have occasionally hedged crude oil and natural gas prices in the past, through the utilization of derivatives, including zero-cost collars and fixed price contracts. Most recently, in July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During the nine months ended September 30, 2008 and 2007, we had recognized losses on derivatives of $8.0 million and $14.4 million, respectively. These contracts expired in April 2008 and we currently have no hedges in place.

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 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 credit facility. We had total indebtedness of $229.4 million outstanding under our credit facility at September 30, 2008. Of this amount, $229.0 million was in LIBOR based traunches and $0.4 million was in prime rate traunches. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $2.3 million per year. Our long-term debt matures in

2011 and the weighted-average interest rate at September 30, 2008 was 3.99%.

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ITEM 4. Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rule 240.13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in reports that it files or submits under the Exchange Act are accumulated and communicated to the issuer s management, including its Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, as appropriate to make timely decisions regarding required disclosures. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer have concluded that our current disclosure controls and procedures are effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission s rules and forms.

There have been no changes in our internal controls over financial reporting during the quarter ended September 30, 2008 that have materially affected or are reasonably likely to materially effect our internal controls over financial reporting.

PART II. Other Information

ITEM 1. Legal Proceedings

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. We are not involved in any legal proceedings nor are we a party to any pending or threatened claims that could reasonably be expected to have a material adverse effect on our financial condition or results of operations.

ITEM 1A. Risk Factors

There has been no change in our risk factors from those disclosed in our Form 10-K for the year ended December 31, 2007.

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

(a) Not applicable.

(b) Not applicable.

(c) Share repurchases.

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number of shares that may yet be purchased under the plans or program
July 1, 2008 to July 31, 2008	829	$ 65.26		
August 1, 2008 to August 31, 2008	2,218	$ 50.97		
September 1, 2008 to September 30, 2008		$		
Total	3,047	$ 54.86		

All shares purchased above represent shares issued pursuant to stock option exercises or restricted stock grants forfeited to cover taxes required to be withheld. The Company paid the associated taxes to the Internal Revenue Service for the required withholding. See *Note 8. Stock Compensation* in Notes to Unaudited Condensed Consolidated Financial Statements.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

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

Not applicable.

ITEM 5. Other Information

Not applicable.

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ITEM 6. Exhibits

See the Exhibit Index accompanying this report.

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SIGNATURE

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.

	Continental Resources, Inc.
Date: November 7, 2008	By: /s/ John D. Hart John D. Hart Vice President, Chief Financial Officer and Treasurer

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INDEX TO EXHIBITS

3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed as Exhibit 3.1 to the Company s Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
3.2	Second Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company s Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
4.1	Registration Rights Agreement filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
4.2	Specimen Common Stock Certificate filed as Exhibit 4.1 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.1	Sixth Amended and Restated Credit Agreement among Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., The Royal Bank of Scotland plc, other financial institutions and banks and Continental Resources, Inc. dated April 12, 2006 filed as Exhibit 10.1 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.2	Omnibus Agreement among Continental Resources, Inc., Hiland Partners, LLC, Harold Hamm, Hiland Partners GP, LLC, Continental Gas Holdings, Inc. and Hiland Partners, LP effective as of the closing of Hiland Partners, LP s initial public offering of common units (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.3	Compression Services Agreement among Hiland Partners, LP and Continental Resources, Inc. effective as of January 28, 2005 (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.4	Gas Purchase Contract between Continental Resources, Inc. and Hiland Partners, LP dated November 8, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Hiland Partners, LP filed on November 10, 2005, Commission File No. 000-51120).
10.5	Strategic Customer Relationship Agreement among Complete Energy Services, Inc., CES Mid-Continent Hamm, Inc. and Continental Resources, Inc. dated October 14, 2004 (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-1 of Complete Production Services, Inc. filed on November 15, 2005, Commission File No. 333-128750).
10.6	Continental Resources, Inc. 2000 Stock Option Plan filed as Exhibit 10.6 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.7	First Amendment to Continental Resources, Inc. 2000 Stock Option Plan filed as Exhibit 10.7 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.8	Form of Incentive Stock Option Agreement filed as Exhibit 10.8 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.9	Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006 filed as Exhibit 10.9 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.10	Form of Restricted Stock Award Agreement filed as Exhibit 10.10 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.11	Amended and Restated Employment Agreement between Continental Resources, Inc. and Mark E. Monroe dated April 3, 2006 filed as Exhibit 10.11 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.12	Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof filed as Exhibit 10.12 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.

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10.13	Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006 filed as Exhibit 10.13 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.14	Crude oil gathering agreement between Banner Pipeline Company, LLC, a wholly owned subsidiary of Continental Resources, Inc. and Banner Transportation Company dated July 11, 2007 filed as Exhibit 99.1 to the Company s Current Report on Form 8-K filed July 11, 2007 and incorporated herein by reference.
31.1 *	Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)
31.2 *	Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)
32 *	Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

* Filed herewith