TETON ENERGY CORP
Form 10-Q
November 06, 2008

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

(Mark One)

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

For quarterly period ended September 30, 2008

or

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

For the transition period from __________ to __________

Commission File Number 1-31679
TETON ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	**84-1482290**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)

600 Seventeenth Street, Suite 1600 North, Denver, Colorado 80202
(Address of principal executive offices) (Zip code)
(303) 565-4600
(Registrant s telephone number, including area code)
410 Seventeenth Street, Suite 1850, Denver, CO 80202
(Former name, former address, and former fiscal year, if changed since last report)

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

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

Large accelerated filer o Accelerated filer þ Non-accelerated filer o Smaller reporting company o

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	Outstanding as of November 3, 2008
Common stock, $.001 par value	22,950,332

TETON ENERGY CORPORATION

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

TETON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEET

(000s except share)

	September 30, 2008 (Unaudited)	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 2,650	$ 24,616
Trade accounts receivable	4,390	2,686
Advances to operator	1,605	
Tubular inventory	852	149
Fair value of oil and gas derivative contracts	938	
Prepaid expenses and other assets	551	131
Deferred debt issuance costs net	551	1,419
Total current assets	11,537	29,001
Oil and gas properties, successful efforts method:		
Developed properties	95,961	35,708
Wells and facilities in progress	9,539	3,230
Undeveloped properties	24,347	13,411
Corporate and other assets	984	485
Total property and equipment	130,831	52,834
Less accumulated depreciation and depletion	(13,768)	(3,695)
Net property and equipment	117,063	49,139
Fair value of oil and gas derivative contracts	867	
Deferred debt issuance costs net	2,190	159
Total assets	$ 131,657	$ 78,299
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 3,000	$ 400
Accrued liabilities	11,295	7,833
Accrued payroll	1,743	902
8% senior subordinated convertible notes, net of discount of $7,370 at December 31, 2007		1,630
Fair value of oil and gas derivative contracts	706	455
Derivative warrant liabilities	2,718	9,522
Total current liabilities	19,462	20,742

Long-term liabilities:				
Long-term debt		55,017		8,000
Asset retirement obligations		1,113		529
Fair value of oil and gas derivative contracts		2,568		
Total liabilities		78,160		29,271
Commitments and contingencies (see Note 10)				
Stockholders equity:				
Preferred stock, $.001 par value; 25,000,000 shares authorized; none outstanding as of September 30, 2008 and December 31, 2007				
Common stock, $.001 par value; 250,000,000 shares authorized; 21,956,395 and 17,652,889 shares issued and outstanding as of September 30, 2008 and December 31, 2007, respectively		22		18
Additional paid-in capital		100,268		76,857
Accumulated deficit		(46,793)		(27,847)
Total stockholders equity		53,497		49,028
Total liabilities and stockholders equity	$	131,657	$	78,299

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

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TETON ENERGY CORPORATION
CONSOLIDATED STATEMENT OF OPERATIONS
(000s except share and per share data)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30, 2008	**September 30, 2007**	**September 30, 2008**	**September 30, 2007**
Operating revenues:				
Oil and gas sales	$ 9,765	$ 1,316	$ 23,526	$ 3,504
Operating expenses:				
Lease operating expense	1,469	196	3,122	303
Transportation expense	695	202	1,295	489
Production taxes	1,096	101	1,723	254
Exploration expense	427	123	1,515	737
General and administrative	3,670	1,766	12,245	5,826
Depreciation, depletion and accretion expense	4,797	1,493	10,094	2,642
Impairment expense	4,034		4,034	
Total operating expenses	16,188	3,881	34,028	10,251
Operating loss	(6,423)	(2,565)	(10,502)	(6,747)
Other income (expense):				
Realized gain (loss) on oil and gas derivative contracts	(989)	528	(2,925)	782
Unrealized gain (loss) on oil and gas derivative contracts	22,465	126	(1,014)	(71)
Gain (loss) on derivative warrant liabilities	5,928	1,935	6,804	(2,694)
Interest expense, net	(1,677)	(976)	(11,311)	(1,268)
Total other income (expense)	25,727	1,613	(8,446)	(3,251)
Net Income (loss)	$ 19,304	$ (952)	$ (18,948)	$ (9,998)
Basic earnings (loss) per common share	$ 0.88	$ (0.06)	$ (0.93)	$ (0.62)
Fully diluted earnings (loss) per common share (see Note 2)	$ 0.74	$ (0.06)	$ (0.93)	$ (0.62)
	21,954,578	16,897,000	20,307,440	16,201,000

Basic weighted-average common shares outstanding				
Fully diluted weighted-average common shares outstanding	27,076,367	16,897,000	20,307,440	16,201,000

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

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TETON ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS
(000s) (Unaudited)

	Nine Months Ended September 30, 2008	September 30, 2007
Operating activities:		
Net loss	$ (18,948)	$ (9,998)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and accretion	10,094	2,642
Impairment of oil and gas properties	4,034	
Amortization of debt issuance costs	1,691	335
Amortization of debt discount	7,370	515
Stock-based compensation expense, exclusive of cash withheld for payroll taxes of $1,127 and $0, respectively	5,601	2,016
Non-cash (gain) loss on derivative warrant liabilities	(6,804)	2,694
Unrealized loss oil and gas derivative contracts	1,014	71
Changes in current assets and liabilities:		
Trade accounts receivable	(1,704)	14
Prepaid expenses, tubular inventory and other current assets	(1,123)	(144)
Accounts payable and accrued liabilities	7,357	800
Accrued payroll	841	(806)
Net cash provided by (used in) operating activities	9,423	(1,861)
Investing activities:		
Proceeds from sale of oil and gas properties		111
Deposits on sale of oil and gas properties		1,000
Acquisition of corporate fixed assets	(499)	(11)
Acquisition and development of oil and gas properties	(70,358)	(28,303)
Net cash used in investing activities	(70,857)	(27,203)
Financing activities:		
Proceeds from issuance of common stock and warrants net of offering costs		4,500
Proceeds from exercise of options/warrants	1,905	2,019
Proceeds from 10.75% Convertible debt (Note 5)	30,000	9,000
Net borrowings on senior bank credit facility	17,017	14,000
Payments on 8% Convertible Notes (Note 5)	(6,600)	
Debt issuance costs	(2,854)	(923)
Net cash provided by financing activities	39,468	28,596

Increase (decrease) in cash and cash equivalents		(21,966)		(468)
Cash and cash equivalents beginning of period		24,616		4,325
Cash and cash equivalents end of period	$	2,650	$	3,857
Supplemental disclosure of cash and non-cash transactions:				
Cash paid for interest, net of amounts capitalized	$	1,625	$	292
Capitalized interest	$	257	$	
Placement agent warrants recorded as equity issuance costs	$		$	190
Placement agent warrants recorded as debt issuance costs	$		$	1,023
Capital expenditures included in accounts payable and accrued liabilities	$	4,372	$	4,850
Stock-based compensation expense included in capital expenditures	$	88	$	
ARO additions and revisions	$	563	$	135
Reclassification of derivative liabilities to stockholder s equity	$		$	3,124
Conversion of Subordinated Debt into Common Stock	$	2,400	$	
Common Stock and Warrants issued in connection with the acqusition of oil and gas properties	$	13,423	$	

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

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TETON ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollar amounts in thousands except per share data)
(Unaudited)

1. General

Basis of Presentation

The accompanying unaudited interim consolidated financial statements were prepared by Teton Energy Corporation (Teton or the Company) pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and note disclosures normally included in the annual consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted as allowed by such rules and regulations. These consolidated financial statements include all of the adjustments, which, in the opinion of management, are necessary for a fair presentation of the financial position and results of operations. All such adjustments are of a normal recurring nature only. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full fiscal year.

Certain amounts in the 2007 financial statements were reclassified to conform to the 2008 unaudited consolidated financial statement presentation, including, but not limited to, presenting revenues on a gross basis before gathering and transportation expenses which are now included in transportation expense on the Consolidated Statement of Operations.

The accounting policies followed by the Company are set forth in Note 1 to the Company s consolidated financial statements in the Annual Report on Form 10-K for the year ended December 31, 2007 (the 2007 Form 10-K), and are supplemented throughout the notes to this quarterly report on Form 10-Q.

The interim consolidated financial statements should be read in conjunction with the financial statements and notes thereto for the year ended December 31, 2007 included in the 2007 Form 10-K filed with the SEC.

Recently adopted accounting pronouncements

On January 1, 2008, the Company adopted the provisions of SFAS No. 157, Fair Value Measurements (SFAS No. 157) related to assets and liabilities, which primarily affect the valuation of our derivative contracts (see Note 4).

In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements that Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13, which removes certain leasing transactions from the scope of SFAS No. 157, and FSP FAS 157-2, Effective Date of FASB Statement No. 157, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. Beginning January 1, 2009, the Company will adopt the provisions for nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis. The adoption of SFAS No. 157 did not have a material effect on the Company s financial condition or results of operations. The Company does not believe that the implementation of this standard, with respect to its effect on nonfinancial assets and liabilities, will have a material impact on its consolidated financial position or results of operations.

On January 1, 2008, the Company adopted the provision of SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159) which permits an entity to measure certain financial assets and financial liabilities at fair value. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. The adoption of SFAS No. 159 did not have a material effect on the Company s financial condition or results of operations as the Company did not make any such elections under this fair value option.

In October 2008, the FASB issued FSP 157-3 Determining Fair Value of a Financial Asset in a Market That Is Not Active (FSP 157-3). FSP 157-3 clarifies the application of SFAS No. 157 in inactive markets. FSP 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued. The implementation of FSP 157-3 did not have a material impact on the Company s consolidated financial position or results of operations.

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New accounting pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS No. 141R will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS No. 141R requires the acquiring Company to measure almost all assets acquired and liabilities assumed in the acquisition at fair value as of the acquisition date. SFAS No. 141R is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied prospectively with the exception of income taxes which should be applied retrospectively for all business combinations. Early adoption is prohibited. The Company is in the process of evaluating the impacts, if any, of adopting this pronouncement.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, (SFAS No. 161), an amendment to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. SFAS No. 161 requires enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. This Statement will be effective for the Company s interim and annual financial statements beginning in fiscal year 2010. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The Company is in the process of evaluating the impacts, if any, of adopting this pronouncement.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS No. 162). SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements presented in conformity with GAAP. SFAS No. 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board (the PCAOB) amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. The Company does not believe that the implementation of this standard will have a material impact on its consolidated financial position or results of operations.

In May 2008, the FASB issued FSP No. APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement, (FSP APB 14-1). FSP APB 14-1 addresses the accounting for convertible debt securities that, upon conversion, may be settled by the issuer either fully or partially in cash. FSP APB 14-1 is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied retrospectively to all past period presented. Early adoption is prohibited. The Company is in the process of evaluating the impacts, if any, of adopting this FSP.

In June 2008, the FASB issued FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 clarified that all outstanding unvested share-based payment awards that contain rights to non-forfeitable dividends participate in undistributed earnings with common shareholders. Awards of this nature are considered participating securities and the two-class method of computing basic and diluted earnings per share must be applied. FSP EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. The Company does not believe that the implementation of this standard will have a material impact on its consolidated financial position or results of operations. At this time, no such instruments exist for the Company.

In June 2008, the FASB ratified the consensus reached by the Task Force, EITF Issue No. 07-5, Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity s Own Stock (EITF 07-5). EITF 07-5 addresses how an entity should evaluate whether an instrument is indexed to its own stock. The consensus is effective for fiscal years (and interim periods) beginning after December 15, 2008 (fiscal 2009 for the Company). The consensus must be applied to outstanding instruments as of the beginning of the fiscal year in which the consensus is adopted and should be treated as a cumulative-effect adjustment to the opening balance of retained earnings. Early adoption is not permitted. The Company is in the process of evaluating the impacts, if any, of adopting this EITF.

In June 2008, the FASB issued EITF 08-4, Transition Guidance for Conforming Changes to Issue No. 98-5 (EITF 08-4). EITF 08-4 provides transition guidance with respect to conforming changes made to EITF 98-5, that result from EITF 00-27, Application of Issue No. 98-5 to Certain Convertible Instruments, and SFAS No. 150, Accounting for

Certain Financial Instruments with Characteristics of both Liabilities and Equity. EITF 08-4 is effective for fiscal years ending after December 15, 2008. Early adoption is permitted. The Company is in the process of evaluating the impacts, if any, of adopting this EITF.

In September 2008, the FASB ratified EITF Issue No. 08-5, Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement (EITF 08-5). EITF 08-5 provides guidance for measuring liabilities issued with an attached third-party credit enhancement (such as a guarantee). It clarifies that the issuer of a liability with a third-party credit enhancement (such as a guarantee) should not include the effect of the credit enhancement in the fair value measurement of the liability. EITF 08-5 is effective for the first reporting period beginning after December 15, 2008. The Company is in the process of evaluating the impacts, if any, of adopting this EITF.

2. Earnings per share of common stock

Basic income (loss) per common share is computed by dividing net income (loss) by the weighted average number of basic common shares outstanding during each period. The shares represented by vested restricted stock and vested performance share units under the Company s 2005 Long Term Incentive Plan (see Note 8) are considered issued and outstanding at September 30, 2008 and 2007, respectively, and are included in the calculation of the weighted average basic common shares outstanding. Diluted income (loss) per common share reflects the potential dilution that would occur if contracts to issue common stock were exercised or converted into common stock.

The following is the calculation of basic and fully diluted weighted average shares outstanding and earnings per share of common stock for the periods indicated:

	Three Months Ended		Nine Months Ended	
	September 30, 2008	September 30, 2007	September 30, 2008	September 30, 2007
Net income (loss)	$ 19,304	$ (952)	$ (18,948)	$ (9,998)
Adjustment for Avoidable Interest (1)	654			
Adjusted Net income (loss)	$ 19,958	$ (952)	$ (18,948)	$ (9,998)
Weighted average common shares outstanding basic	21,954,578	16,897,000	20,307,440	16,201,000
Dilution effect of restricted stock, performance share units, stock options and warrants	5,121,789			
Weighted average common shares outstanding fully diluted	27,076,367	16,897,000	20,307,440	16,201,000
Earnings (loss) per share of common stock:				
Basic	$ 0.88	$ (0.06)	$ (0.93)	$ (0.62)
Fully diluted	$ 0.74	$ (0.06)	$ (0.93)	$ (0.62)

(1) Net income for fully diluted EPS was adjusted by interest paid or

accrued for the three months ended September 30, 2008 related to the 10.75% Secured Convertible Debentures. Under the if-converted method provided for in SFAS No. 128, interest charges applicable to convertible debt shall be added back to the numerator for purposes of computing fully diluted earnings per share.

The following securities, which could be potentially dilutive in future periods, were not included in the computation of diluted net income per share because the effect would have been anti-dilutive for the periods indicated:

	Three Months Ended		**Nine Months Ended**	
	September 30, 2008	**September 30, 2007**	**September 30, 2008**	**September 30, 2007**
Convertible Notes		1,800,000	2,668,669	1,800,000
Warrants	2,029,747	5,242,366	2,164,434	5,242,366
Stock options		1,523,067	350,786	1,523,067
LTIP Performance Units	171,875	2,365,236	222,711	2,365,236
Restricted Common Stock		202,333	79,905	202,333
Total	2,201,622	11,133,002	5,486,505	11,133,002

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The above amounts are calculated using the treasury stock method, whereby a company uses the proceeds from the exercise or purchase of shares as well as the average unrecognized compensation to repurchase common stock at the average market price during the period. This is the prescribed method used to calculate the dilutive shares in fully diluted earnings per share calculations. At September 30, 2008, the maximum number of shares that could potentially be included in the basic earnings per share calculation, if all shares above were exercised, purchased or converted is 12,117,312 shares. On October 7, 2008, the Company exchanged 990,000 shares of common stock for 3,960,000 warrants, effectively reducing the maximum number of potential shares to be issued pursuant to such warrants by 2,970,000 (See Note 5).

3. Oil and Gas Properties

Acquisitions

On April 2, 2008, the Company completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas from Shelby Resources, LLC (Shelby), a private oil and gas company and a group of approximately 14 other working interest owners, for approximately $53.6 million, after post closing adjustments. Terms also included warrant coverage of 625,000 shares at a $6.00 strike price with a two-year term. The effective date of the transaction was March 1, 2008.

The purchase price was funded with $40.2 million of cash and borrowing capacity available under Teton s revolving credit facility with JPMorgan Chase (see Note 6), $13.0 million of Teton common stock, or 2,746,124 common shares, and 625,000 warrants valued at $434. Effective April 2, 2008, Teton amended its bank credit facility with JPMorgan, increasing the total facility from $50 million to $150 million. The available borrowing base under Teton s bank credit facility was increased from $10 million to $50 million as a result of the combination of the added reserves from this transaction, ongoing drilling programs and new hedging positions. The Company hedged 80 percent of the oil proved developed producing (PDP) production and 80 percent of the natural gas PDP production related to this transaction for five years through a series of costless collars in order to lock in base case economics associated with the acquisition (see Note 10).

The purchase price was allocated using the purchase method of accounting with Teton treated as the acquirer. Under this method of accounting, the assets and assumed liabilities of Shelby are recorded by Teton at their estimated fair values as of the respective dates the acquisition was deemed to have occurred.

The following table shows the allocation of the purchase price to the assets acquired and liabilities assumed from Shelby Resources on April 2, 2008.

Allocation of Purchase Price

Undeveloped properties	$	11,371
Oil and gas properties and related facilities	$	42,057
Asset retirement obligations	$	193
	$	53,621

The following unaudited summarized pro forma information gives effect to the acquisition of the interests of Shelby by Teton as if the assets had been acquired as of January 1, 2007.

Proforma Supplemental Information:

	For the Nine Months Ended September 30,			
	2008		2007	
Revenues	$	26,676	$	11,346
Net income	$	(18,251)	$	(8,081)

Earnings per share	$	(0.90)	$	(0.43)

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The unaudited pro forma combined condensed financial information is for illustrative purposes only. The financial results may have been different had Teton and Shelby always been combined. You should not rely on the unaudited pro forma combined condensed financial information as being indicative of the historical results that would have been achieved had the acquisition occurred in the past or the future financial results that Teton will achieve after the acquisition.

Impairment of Long-Lived Assets

The Company reviews the carrying values of its long-lived assets whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If, upon review, the sum of the estimated undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The long-lived assets of the Company, which are subject to periodic evaluation, consist primarily of oil and gas properties including undeveloped leaseholds. The Company incurred impairment expenses of $4,034 and $0 during the three months ended September 30, 2008 and 2007, respectively, and $4,034 and $0 during the nine months ended September 30, 2008 and 2007, respectively.

As of September 30, 2008 there were 112 producing wells, 10 wells waiting on completion and four waiting on pipeline in the Company s non-operated properties in the Teton-Noble AMI in the DJ Basin. Twenty-one wells were waiting on or in the process of having pumping units installed, which the operator has informed the Company will increase production and well performance. Additionally, the operator has informed the Company that the gathering system is also in process of being optimized to improve well performance. The production from these wells, which is currently lower than expected, has resulted in lower reserve estimates being assigned to the wells. At September 30, 2008, the carrying value of the Teton-Noble AMI developed properties exceeded the undiscounted future net revenues estimated to be derived from the wells. As a result, the Company has determined that $2,267 of capitalized costs (the amount by which the carrying value exceeds the fair value) related to the non-operated properties in the Teton-Noble AMI is impaired, and that amount has been charged to expense in the quarter ended September 30, 2008. The fair value was determined as the discounted net present value of the future cash flows using a 10% discount factor. Additionally, the carrying value of the undeveloped acreage for the Teton-Noble AMI exceeded its fair value by $1,767, and that amount has also been charged to expense in the quarter ended September 30, 2008.

Suspended Well Costs

The Company had no exploratory well costs that had been suspended for a period of one year or more as of September 30, 2008 or 2007.

Asset Retirement Obligations

The Company s asset retirement obligations represent the estimated future costs associated with the plugging and abandonment of oil and gas wells and removal of related equipment and facilities, in accordance with applicable state and federal laws. The following table provides a reconciliation of the Company s asset retirement obligations:

	Nine Months Ended September 30, 2008
Asset retirement obligation beginning of period	$ 529
Additional liabilities incurred	465
Revisions in estimated cash flows	98
Accretion expense	21
Asset retirement obligation end of period	$ 1,113

4. Fair Value of Financial Instruments

Effective January 1, 2008, the Company adopted the provisions of SFAS No. 157 for all financial instruments. The valuation techniques required by SFAS No. 157 are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent resources, while unobservable inputs reflect the Company s market assumptions. The standard established the following fair value hierarchy:

Level 1 Quoted prices for identical assets or liabilities in active markets.

Level 2 Quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; and model-derived valuations whose inputs or significant value drivers are observable.

Level 3 Significant inputs to the valuation model are unobservable.

The following describes the valuation methodologies we use to measure financial instruments at fair value.

Debt and Equity Securities

The recorded value of the Company s long-term debt approximates its fair value as it bears interest at a floating rate. The Company s Secured Convertible Notes (Convertible Notes) were a negotiated instrument and are therefore recorded at fair value. The Company evaluated the Convertible Notes and determined that the instruments qualified as conventional convertible securities and did not contain any embedded features which would require derivative accounting.

Derivative Instruments

The Company uses derivative financial instruments to mitigate exposures to oil and gas production cash flow risks caused by fluctuating commodity prices. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as liabilities or assets on the balance sheet. For oil and gas derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in the consolidated statement of operations. When oil and gas derivative contracts are settled, the Company recognizes realized gains and losses under the other income and expense caption in its consolidated statement of operations. At September 30, 2008, the Company did not have any derivative contracts that qualify as cash flow hedges.

Derivative assets and liabilities included in Level 2 include fixed-rate swap arrangements for the sale of oil and natural gas and hedge contracts, valued using the Black-Scholes-Merton valuation technique, in place through 2013 for a total of approximately 485,417 Bbls of oil production and 2,124,682 MMbtu of natural gas production.

The Company also uses various types of financing arrangements to fund its business capital requirements, including convertible debt and other financial instruments indexed to the market price of the Company s common stock. The Company evaluates these contracts to determine whether derivative features embedded in host contracts require bifurcation and fair value measurement or, in the case of free-standing derivatives (principally warrants), whether certain conditions for equity classification have been achieved. In instances where derivative financial instruments require liability classification, the Company initially and subsequently measures such instruments at estimated fair value using Level 2 inputs. Accordingly, the Company adjusts the estimated fair value of these derivative components at each reporting period through earnings until such time as the instruments are exercised, expired or permitted to be classified in stockholders equity.

As of September 30, 2008, the fair value of financing warrants included as a component of current liabilities consisted of warrants to purchase 3,600,000 shares of the Company s common stock that do not achieve all of the requisite conditions for equity classification. These free-standing derivative financial instruments arose in connection with the Company s financing transaction in May 2007 which consisted of the $9.0 million Convertible Notes and warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price for a period of five years (with a cashless exercise option). Effective October 7, the Company and all of the investors that held the 3,600,000 warrants agreed to exchange the warrants for 900,000 shares of the Company s common stock. As a result, the carrying value of the current liability for the financing warrants was reduced to the fair value as of September 30 based upon the number of shares exchanged for the warrants and the stock price on the measurement date, September 30, 2008, resulting in a gain of $5,928 that is included in the Consolidated Statement of Operations. The Company will recognize an additional gain in October of $958 based upon the stock price at the date of exchange.

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On April 2, 2008, in conjunction with the purchase of production and reserves related to certain oil and gas producing properties in the Central Kansas Uplift, the Company issued 625,000 warrants to acquire shares of Teton common stock. Each warrant is exercisable on or after July 2, 2008 at an exercise price of $6.00 per share, and expires on April 1, 2010. The Company evaluated these instruments in accordance with SFAS No. 133 and EITF 00-19 and determined, based on the facts and circumstances, that these instruments qualify for classification in stockholders equity and therefore are not reported as a liability or measured at fair value on a recurring basis.

The following table summarizes Teton s assets and liabilities measured at fair value on a recurring basis at September 30, 2008.

	Level 1	Level 2	Level 3	Total
Assets:				
Oil and gas derivative contracts	$	$ 1,805	$	$ 1,805
Liabilities:				
Oil and gas derivative contracts	$	$ 3,274	$	$ 3,274
Derivative contracts Warrants		2,718		2,718
	$	$ 5,992	$	$ 5,992

5. Convertible Notes

<u>8% Senior Subordinated Convertible Notes</u>

On May 16, 2008, the Company repaid, to the extent not converted, its $9.0 million face value of 8% Senior Subordinated Convertible Notes that closed on May 16, 2007 (the Notes). $6.6 million was repaid in cash and $2.4 million was converted to 480,000 shares of common stock at a conversion price of $5.00 per share.

The $9.0 million debt component of the Notes was initially recorded net of debt issuance discount of $9.0 million. The debt issuance discount was amortized to interest expense over the life of the Notes using the effective interest method. The Company recorded $0 and $7,370 of debt issuance discount amortization during the three and nine months ended September 30, 2008, respectively.

Additionally, the Company recorded $0 and $1,419 of amortization of deferred debt issuance costs during the three and nine months ended September 30, 2008, respectively, related to the Notes.

The warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price for a period of five years issued in connection with the Notes include a cashless exercise feature. In addition, on May 18, 2007, the Company issued to the placement agent for this offering warrants to purchase 360,000 shares of the Company s common stock at a $5.00 strike price with a term of five years.

Effective October 7, 2008, the Company entered into a Warrant Exchange Agreement, dated October 4, 2008, with all of the holders of the stock purchase warrants issued on May 16, 2007 and the placement agent warrants issued on May 18, 2007, to exchange the warrants for an aggregate of 990,000 shares of the Company s common stock, par value $0.001. The warrants are carried on the Company s balance sheet as a current liability at fair value. At September 30, 2008, the fair value of the 3,600,000 derivative warrant liabilities of $2,718 was equal to the exit value on the date of the exchange.

<u>10.75% Secured Convertible Debentures</u>

On June 18, 2008, the Company closed the private placement of $40 million aggregate principal amount of 10.75% Secured Convertible Debentures due on June 18, 2013 (the Debentures). The Debentures are convertible by the holders at a conversion rate of $6.50 per share and contain a two year no-call provision and a provisional call thereafter if the price of the underlying common stock of the Company exceeds the conversion price by 50%, or is $9.75, for any 20 trading days in a 30 trading-day period. If the holders convert into common stock, or the Debentures are called by the Company before the three-year anniversary of the original issuance date, the holders will be entitled to a payment in an amount equal to the present value of all interest that would have accrued if the principal amount had remained outstanding through such three-year anniversary. The Debentures are secured by a second lien on all assets in which the Company s senior lender maintains a first lien.

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The Debentures bear interest at a rate of 10.75% per year payable semiannually in arrears on July 1 and January 1 of each year beginning with July 1, 2008. The holders each had a 90-day put option, expiring September 18, 2008, whereby they elected to reduce their investment in the Debentures by a total of 25% of the face amount, or $10 million in the aggregate. The Company repaid the $10 million to its investors on September 18, 2008, reducing the total outstanding amount on the Debentures to $30 million.

The net proceeds from the issuance of the Debentures, after fees and related expenses (and excluding the 90-day 25% put options) were approximately $28 million. These funds were used to pay down the Company s outstanding indebtedness on its revolving credit facility (see Note 6).

On September 19, 2008, the Company entered into the Secured Subordinated Convertible Debenture Indenture (the Indenture) with each of the Company s subsidiary guarantors and the Bank of New York Mellon Trust Company, N.A., a national banking association (Bank of New York or the Trustee), and, in an exchange transaction on the same date, pursuant to the Purchase Agreement and the Indenture, the Company exchanged the Original Debentures for a Global Debenture in the amount of $30 million, which the Company deposited with the Depository Trust Company (DTC) and registered in the name of Cede & Co., as DTC s nominee. Pursuant to the Indenture, Bank of New York is acting as Trustee with respect to the Global Debenture and the Company s obligations thereunder. Initially, the Trustee is also serving as the paying agent, conversion agent and registrar with respect to the Indenture.

In connection with the Exchange and the closing of the Indenture, the Company entered into a letter agreement with each of the parties to the original Purchase Agreement, which amends and supplements the Purchase Agreement to, among other things, appoint Bank of New York as Representative, replacing Whitebox Advisors, LLC. The Company also entered into an amended and restated Intercreditor and Subordination Agreement with JPMorgan Chase and Bank of New York, and an amended and restated Subordinated Guaranty and Pledge Agreement, which reflect, among other things, the Exchange and the appointment of Bank of New York as successor in interest to Whitebox Advisors LLC as Representative and collateral agent.

Deferred debt issuance costs of $2,741 associated with the Convertible Notes are included in assets as of September 30, 2008 and will be amortized to interest expense over the life of the related Debenture. Additionally, the Company recorded $130 and $148 of amortization of deferred debt issuance costs during the three and nine months ended September 30, 2008, respectively, related to the Notes.

6. Senior Bank Facility

On August 9, 2007, the Company s $50 million revolving credit facility with BNP Paribas (the Credit Facility) was replaced by an amended and restated $50 million revolving credit facility with JPMorgan Chase, as administrative agent. JPMorgan Chase assumed the Company s previous Credit Facility with BNP Paribas. The amended Credit Facility originally was scheduled to mature on August 9, 2011. On April 2, 2008, the Company again amended its Credit Facility (the Amended Credit Facility) to a $150 million revolving credit facility ($50 million borrowing base).

In connection with the privately placed 10.75% Secured Convertible Debenture, the borrowing base on the Company s $150 million revolving credit facility was reduced from $50 million to $32.5 million. On August 1, 2008 the borrowing base was re-determined and increased to $34.5 million.

Prior to the 90-day anniversary of the Original Issue Date of the Company s privately placed 10.75% Secured Convertible Debentures, the holders elected to exercise their 90-day put option as discussed in Note 5. The Company repaid the $10 million in principal amount of the Debentures, reducing the total outstanding amount to $30 million. As a result, the Company s total available borrowings under the Debentures and the Amended Credit Facility are $64.5 million as of September 30, 2008.

Under the Amended Credit Facility, at the option of the Company, each loan bears interest at a Eurodollar rate (London Interbank Offered Rate, or LIBOR) plus applicable margins of 1.25% to 2.25% or a base rate (the higher of the Prime Rate or the Federal Funds Rate plus 0.5%) plus applicable margins of 0% to .75%, determined on a sliding scale based on the percentage of total borrowing base in use. The Company is also required to pay a commitment fee of 0.375% to 0.5% per annum, based on the daily average unused amount of the commitment. Loans made under the Amended Credit Facility are secured primarily by a first mortgage against the Company s oil and gas assets, by a pledge of the Company s equity interests in its subsidiaries and by a guaranty by its subsidiaries. The Amended Credit Facility contains customary affirmative and negative covenants such as minimum/maximum ratios for liquidity and leverage.

The Company borrowed on its Amended Credit Facility during the second quarter of 2008 to fund the acquisition of certain oil and gas properties in the Central Kansas Uplift and to repay $6.6 million of the 8% Senior Secured Convertible Notes. With the gross proceeds of the $30 million privately placed 10.75% Secured Convertible Debentures (see Note 5 above), on June 18, 2008, the Company repaid approximately $28 million on its Amended Credit Facility. During the third quarter of 2008, the Company borrowed a net $3 million on its Amended Credit Facility to fund the exploration and development of its operated properties in the Central Kansas Uplift and non-operated properties in the Piceance Basin and the Teton-Noble AMI.

The balance outstanding at September 30, 2008 was approximately $25 million. For the three and nine months ended September 30, 2008, cash interest expense with respect to the above credit lines and the Convertible Notes described in Note 5 totaled $1,629 and $2,778, respectively, and capitalized interest totaled $102 and $257, respectively.

7. Stockholders Equity

Warrants

The following table presents the composition of warrants outstanding and exercisable as of September 30, 2008:

Range of Exercise Prices	Number	Weighted Average Remaining Contractual Life (years)
$ 3.24	232,904	4.2
$ 4.35	200	0.1
$ 5.00	3,960,000	3.6
$ 6.00	625,000	1.5
$ 6.06	414,547	3.8
Total warrants outstanding and exercisable	5,232,651	3.4

The above amount includes 3,600,000 warrants and 360,000 placement agent warrants, issued in connection with the $9.0 million face value of 8% Senior Subordinated Convertible Notes issued in May 2007, which were exchanged for 990,000 shares of the Company s common stock on October 7, 2008. These warrants had an expiration date of May 2012 and an exercise price of $5.00 with a cashless exercise option.

On April 2, 2008, in conjunction with the purchase of production, reserves and certain oil and gas producing properties in the Central Kansas Uplift, the Company issued 625,000 warrants to acquire shares of Teton common stock. Each warrant is exercisable on or after July 2, 2008 at an exercise price of $6.00 per share and expires on April 1, 2010. The Company evaluated these instruments in accordance with SFAS No. 133 and EITF 00-19 and determined, based on the facts and circumstances, that these instruments qualify for classification in stockholders equity.

8. Stock-Based Compensation

During 2008, 2,904,614 performance share units, net of forfeitures, were granted to participants, pursuant to the 2005 Long Term Incentive Plan (LTIP) by the Compensation Committee of the Company s Board of Directors (the 2008 Grants). The 2008 Grants vest in three tranches, provided the goals set forth by the Compensation Committee are met. The performance measures under these Awards are based on increases in the Company s net asset value per share. The grants vest at 20%, 30% and 50% when the net asset value per share of the Company increases by 40%, 100% and 200%, respectively, from a base level set by the Compensation Committee as of December 31, 2007. An additional 385,250 shares of restricted common stock, net of forfeitures, granted pursuant to the Company s LTIP, were awarded during the nine months ended September 30, 2008. These shares vest over three years based solely on service.

Compensation expense is recorded at fair value based on the market price of the Company s common stock at the date of grant and is recognized over the related service period. During the three and nine months ended September 30, 2008, the Company recorded $1.5 million and $6.7 million for stock-based compensation expense, respectively, applicable to the vesting of LTIP performance units (including the first tranche of the 2008 LTIP awards) and restricted stock grants. The Company expects to recognize approximately an additional $1.5 million during the twelve months ending December 31, 2008 related to the LTIP performance-vesting and restricted stock grants outstanding at September 30, 2008.

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9. Income Taxes

For each of the three and nine months ended September 30, 2008 and 2007, the current and deferred provision for income taxes was $0.

At December 31, 2007, the Company had net operating loss carryforwards (NOLs), for federal income tax purposes, of approximately $32.5 million. These NOLs, if not utilized to reduce taxable income in future periods, will expire in various amounts from 2018 through 2027. Approximately $5.8 million of such NOLs is subject to U.S. Internal Revenue Code Section 382 limitations. As a result of these limitations, utilization of this portion of the NOLs is limited to approximately $3.6 million and $2.2 million for the years ending December 31, 2008 and 2009, respectively, plus any loss attributable to any built-in gain on assets sold within five years of the ownership change.

On January 1, 2007, the Company adopted the provisions of FIN 48, which requires that the Company recognize in its consolidated financial statements only those tax positions that are more-likely-than-not of being sustained as of the adoption date, based on the technical merits of the position. As a result of the implementation of FIN 48, the Company performed a comprehensive review of its material tax positions in accordance with recognition and measurement standards established by FIN 48. The Company had no accrued interest or penalties related to uncertain tax positions as of September 30, 2008.

10. Commitments and Contingencies

To mitigate a portion of the potential exposure to adverse market changes in the prices of oil and natural gas, the Company has entered into various derivative contracts. The outstanding commodity hedges as of September 30, 2008 are summarized below:

Type of Contract	Remaining Volume	Fixed Price (1)	Price Index (2)	Remaining Period
Oil Fixed Price Swap	5,520	$80.70	WTI	10/01/08-12/31/08
Oil Costless Collar	36,753	$95.80 Floor/$103.00 Ceiling	WTI	10/01/08-12/31/08
Oil Costless Collar	143,545	$90.00 Floor/$104.00 Ceiling	WTI	01/01/09-12/31/09
Oil Costless Collar	106,876	$90.00 Floor/$104.00 Ceiling	WTI	01/01/10-12/31/10
Oil Costless Collar	87,920	$90.00 Floor/$104.00 Ceiling	WTI	01/01/11-12/31/11
Oil Costless Collar	79,611	$90.00 Floor/$104.00 Ceiling	WTI	01/01/12-12/31/12
Oil Costless Collar	25,192	$90.00 Floor/$104.00 Ceiling	WTI	01/01/13-04/30/13
Total Bbl	485,417			
Natural Gas Fixed Price Swap	30,000	$5.78	CIGRM	10/01/08-10/31/08
Natural Gas Costless Collar	184,000	$6.00 Floor/$7.10 Ceiling	CIGRM	10/01/08-12/31/08
Natural Gas Costless Collar	62,000	$6.00 Floor/$7.10 Ceiling	CIGRM	01/01/09-01/31/09
Natural Gas Costless Collar	473,867	$6.50 Floor/$7.75 Ceiling	CIGRM	02/01/09-12/31/09
Natural Gas Costless Collar	417,405	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/10-12/31/10
Natural Gas Costless Collar	355,399	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/11-12/31/11
Natural Gas Costless Collar	310,702	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/12-12/31/12
	95,200	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/13-04/30/13

Natural Gas Costless Collar				
Natural Gas Costless Collar	26,685	$9.10 Floor/$9.75 Ceiling	NYMEX	10/01/08-12/31/08
Natural Gas Costless Collar	77,630	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/09-12/31/09
Natural Gas Costless Collar	46,274	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/10-12/31/10
Natural Gas Costless Collar	26,158	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/11-12/31/11
Natural Gas Costless Collar	15,258	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/12-12/31/12
Natural Gas Costless Collar	4,104	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/13-04/30/13
Total MMBtu	2,124,682			

(1) Fixed price is per Bbl for oil swaps and collars and per MMBtu for natural gas swaps and collars.

(2) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platts for Inside FERC on the first business day of each month. NYMEX refers to quoted prices on the New York Mercantile Exchange. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

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On April 30, 2008, the Company entered into a lease agreement for new office space in Denver beginning September 1, 2008 for a period of 69 months. As of September 30, 2008, the start of the new lease agreement has been delayed to November 1, 2008. Rental payments, before expenses, under the lease are $32,509 for the remainder of 2008, $224,148 for 2009 and an aggregate $1,283,374 thereafter, for the remaining 55 months of the agreement. After November 1, 2008, the Company has no further obligations under its current lease agreement.

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

($ amounts in thousands, except amounts per unit of production)

The terms Teton, Company, we, our and us refer to Teton Energy Corporation and its subsidiaries, as a conso entity, unless the context suggests otherwise.

Forward-Looking Statements

This Quarterly Report on Form 10-Q contains both historical and forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements, written, oral or otherwise made, represent the Company s expectation or belief concerning future events. All statements, other than statements of historical fact, are or may be forward-looking statements. For example, statements concerning projections, predictions, expectations, estimates or forecasts, and statements that describe our objectives, future performance, plans or goals are, or may be, forward-looking statements. These forward-looking statements reflect management s current expectations concerning future results and events and can generally be identified by the use of words such as may, will, should, could, would, likely, predict continue, future, estimate, believe, expect, anticipate, intend, plan, foresee and other similar words as statements in the future tense.

Forward-looking statements involve known and unknown risks, uncertainties, assumptions, and other important factors that may cause our actual results, performance or achievements to be different from any future results, performance and achievements expressed or implied by these statements. The following important risks and uncertainties could affect our future results, causing those results to differ materially from those expressed in our forward-looking statements:

- General economic and political conditions, including governmental energy policies, tax rates or policies, inflation rates and constrained credit markets;
- The market price of, and supply/demand balance for, oil and natural gas;
- Our ability to service current and future indebtedness;
- Our success in completing development and exploration activities;
- Reliance on outside operating companies for drilling and development of our non-operated oil and gas properties;
- Expansion and other development trends of the oil and gas industry;
- Acquisitions and other business opportunities that may be presented to and pursued by us;
- Our ability to integrate our acquisitions into our company structure; and
- Changes in laws and regulations.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors, including unknown or unpredictable ones, could also have material adverse effects on our future results.

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The following discussion should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations included in our 2007 Annual Report on Form 10-K.

Overview and Strategy

We are an independent oil and gas exploration and production company focused on the acquisition, exploration and development of North American properties. The Company s current operations are concentrated in the prolific Midcontinent and Rocky Mountain regions of the U.S. We have leasehold interests in the Central Kansas Uplift, the Piceance Basin in western Colorado, the eastern Denver-Julesburg Basin in Colorado, Kansas and Nebraska, the Williston Basin in North Dakota and the Big Horn Basin in Wyoming.

Teton was formed in November 1996 and is incorporated in the State of Delaware. Effective September 8, 2008, our common shares are publicly traded on the NASDAQ Capital Market LLC under the symbol TEC. Prior to September 8, 2008, our common shares were publicly traded on the American Stock Exchange under the symbol TEC .

Our principal executive offices are located at 600 Seventeenth Street, Suite 1600 North, Denver, CO 80202, and our telephone number is (303) 565-4600. Our web site is *www.teton-energy.com*.

Our objective is to increase stockholder value by pursuing our corporate strategy of:

- economically growing reserves and production by acquiring under-valued properties with reasonable risk-reward potential and by participating in, or actively conducting, drilling operations in order to further exploit our existing properties;
- seeking high-quality exploration and development projects with potential for providing operated, long-term drilling inventories; and
- selectively pursuing strategic acquisitions that may expand or complement our existing operations.

The pursuit of our strategy includes the following key elements:

Pursue Attractive Reserve and Leasehold Acquisitions

To date, acquisitions have been critical in establishing our asset base. We believe that we are well suited, given our initial success in identifying and quickly closing on attractive opportunities in the Central Kansas Uplift, Piceance, DJ, Williston and Big Horn Basins, to effect opportunistic acquisitions that can provide upside potential, including long-term drilling inventories and undeveloped leasehold positions with attractive return characteristics. Our focus is to acquire assets that provide the opportunity for developmental drilling and/or the drilling of extensional step-out wells, which we believe will provide us with significant upside potential while not exposing us to the risks associated with drilling new field wildcat wells in frontier basins.

Drive Growth through Drilling

We plan to supplement our long-term reserve and production growth through drilling operations. In 2007, we participated in the drilling of 41 gross wells in connection with our Piceance Basin project where we have a 12.5% non-operated working interest and 81 gross wells in the DJ Basin under the Noble Earning Agreement where we have a 25% non-operated working interest in the AMI. In 2008, we anticipate that we will participate in the drilling of approximately 52 gross wells, of which 47 have been spud as of September 30, 2008, in the Berry Petroleum Company (Berry) operated properties in the Piceance Basin, and in the drilling of approximately 105 gross wells, of which 69 have been spud as of September 30, 2008, in the Noble-operated properties in the Teton Noble AMI. During 2008, we also anticipate that we will drill up to 20 gross wells in the Central Kansas Uplift properties (see further discussion below).

Maximize Operational Control

It is strategically important to our future growth and maturation as an independent exploration and production company to be able to serve as operator of our properties when possible in order to be able to exert greater control over costs and timing in, and the manner of, our exploration, development and production activities. In 2007, we acquired 499,904 gross acres (413,786 net) in the DJ Basin Washco properties, including about 1.0 MMcfed of production, 111,872 gross acres (109,688 net) in the DJ Basin South Frenchman Creek properties, 28,204 gross acres (11,689 net) in the DJ Basin Frenchman Creek properties and 16,417 gross acres (15,132 net) in the Big Horn Basin properties (further increased to over 33,000 gross acres at September 30, 2008), all of which are properties operated by us. On April 2, 2008, we acquired an additional 48,100 gross acres (31,650 net) in the Central Kansas Uplift, all of which is also operated by us (see further discussion below). We currently have eight projects; five operated by the Company and three operated by other companies.

Operate Efficiently and Effectively, and Maximize Economies of Scale Where Practical
Our objective is to generate profitable growth and high returns for our stockholders, and we expect that our unit cost structure will benefit from economies of scale as we grow and from our continuing cost management initiatives. As we manage our growth, we are actively focusing on reducing lease operating expenses and finding and development costs. In addition, our acquisition efforts are geared toward pursuing opportunities that fit well within existing operations, in areas where we are establishing new operations or in areas where we believe that a base of existing production will produce an adequate foundation for economies of scale.
Pursuit of Selective Complementary Acquisitions
We seek to acquire long-lived producing properties with a high degree of operating control, or oil and gas concerns that enjoy good business reputations and that offer economical opportunities to increase our natural gas and crude oil reserves.
As an example of this strategy, on April 2, 2008, we completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas from Shelby Resources, LLC, a private oil and gas company and a group of approximately 14 other working interest owners, collectively (the Sellers) for approximately $53.6 million. Terms also include warrant coverage of 625,000 shares at a $6.00 strike price with a two-year term. The effective date of the transaction was March 1, 2008.
The purchase price was funded with $40.2 million of cash, $13.0 million of Teton common stock, or 2,746,124 common shares, and 625,000 warrants valued at $434. Effective April 2, 2008, we amended our bank credit facility with JPMorgan, increasing the total facility from $50 million to $150 million (the Amended Credit Facility). The available borrowing base under the Amended Credit Facility was increased from $10 million to $50 million ($32.5 million at September 30, 2008 as discussed in Note 6 of the Notes to the Consolidated Financial Statements) as a result of the combination of the added reserves from this transaction, ongoing drilling programs and new hedging positions. We hedged 80 percent of the estimated oil proved developed producing (PDP) production and 80 percent of the estimated natural gas PDP production related to this transaction for five years through a series of costless collars in order to lock in base case economics associated with the acquisition.
Following are summary comments of our performance in several key areas during the three and nine month periods ended September 30, 2008:
Net income (loss)
During the three and nine month periods ended September 30, 2008, we moved from a net loss of $952 (or $0.06 per common share) for the three months ended September 30, 2007 to net income of $19,304 (or $0.88 per common share) for the three months ended September 30, 2008, and the net loss increased from $9,998 (or $0.62 per common share) to $18,948 (or $0.93 per common share) for the nine months ended September 30, 2008. The positive change in income of $20,256 for the three month period is due largely to an increase in the unrealized gain on oil and gas derivative contracts, a non-cash item required by SFAS No. 133, of $22,339; an increase in unrealized gain on derivative contracts of $3,993 due to a decrease in the fair value of the related warrant liability; and an increase in oil and gas revenues, from $1,316 to $9,765 during the three months ended September 30, 2008. These increases in net income were somewhat offset by a one-time charge to impairment expense related to the Teton-Noble AMI during the third quarter of 2008 of $4,034; an increase in lease operating and related production expenses (due primarily to increased production and production in new locations with higher oil production and resultant per unit LOE that is slightly higher, to increased production taxes related both to increased production and assessed values, as well as to adjustments to prior period ad valorem taxes and to increased DD&A related to increased production on a higher capitalized asset base); an increase in general and administrative expenses of $1,904 (largely due to an increase in both cash and non-cash compensation related to additional head count added since September 30, 2007); and an increase in interest expense of $701 related to higher outstanding debt levels. The increase in net loss of $8,950 for the nine month period is due largely to a one-time charge to impairment expense related to the Teton-Noble AMI during the third quarter of 2008 of $4,034; an increase in the unrealized loss on oil and gas derivative contracts, a non-cash item required by SFAS No. 133, of $943; an increase in realized loss on oil and gas derivative contracts of $3,707; an increase in general and administrative expenses of $6,419 (largely due to the increase in non-cash compensation related to the vesting of the first tranche of the 2008 LTIP and awards given to new employees); an increase in

non-cash interest expense related to the amortization of deferred debt discount and issuance costs of $8,937; and less significantly to an increase in lease operating and related production expenses (due primarily to increased production and production in new locations with heavy oil productions and resultant per unit LOE that is slightly higher, and to increased production taxes related both to increased production and assessed values, as well as to adjustments to prior period ad valorem taxes). These increases were offset by a 571% increase in oil and gas revenues, from $3,504 to $23,526 and a $9,498 increase in the gain on derivative liabilities (related to the exchange of warrants for 990,000 shares of common stock) during the nine months ended September 30, 2008.

Production

During the three and nine month periods ended September 30, 2008, average company-wide daily production increased 104%, to 9,047 Mcfed, and 120%, to 7,074 Mcfed, respectively, as compared to average daily production of 4,429 Mcfed and 3,210 Mcfed, respectively, during the same prior year periods. The fluctuations in production by major operating area are discussed below.

Central Kansas Uplift. On April 2, 2008, we completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift (CKU), and we began recognizing our share of production from the 50 producing wells at that time. Average daily production, net to the Company, from the area was 3,344 Mcfed and 2,294 Mcfed for the three and nine months ended September 30, 2008, respectively. The second quarter 2008 was our first production from the Central Kansas properties. We closed on April 2, 2008, and formally took over operations at the end of April, retaining the prior owner on a contract for advisory services through the end of 2008 in order to take advantage of its significant expertise in the area. We had intended to drill up to an additional 40 gross wells in the Central Kansas Uplift in 2008, but, due largely to the current world-wide credit and capital markets constraints, have changed our planned drilling to up to 20 wells (see additional discussion under Liquidity and Capital Resources). As of October 22, 2008, we have spud 17 wells, of which ten have been determined to be economically viable producing wells and two others are being completed as salt water disposal wells. Pipe has been run on the ten producing wells encountering both the Arbuckle and the Lansing/Kansas City oil (see additional discussion under Results of Operations below). Five of the wells drilled will not be completed, including the original two wells drilled in the second quarter 2008 after we assumed operations and three additional wells that were determined to be non-economical in October. In the past, we have been using outside resources to select the drilling locations. We now have added geological and geophysical professionals to our staff and believe that will greatly increase our success rate in Kansas. The historical success rate on this property has been approximately 80-85%, and we believe that we can return to that level of results. By cutting back the number of wells planned to drill in the remainder of 2008, it allows our geosciences staff to become more familiar with the area and gives them the time needed to study and select the 2009 drilling locations. We also intend to drill up to an additional three wells in 2008 within the CKU AMI with our partners.

The average well profile we acquired was for new wells to come on production at approximately 40-50 Bopd with a 40,000-50,000 barrel EUR. Based on the wells we have successfully drilled to date, we now expect the average well to come on production at about 30-35 Bopd with a 30,000-35,000 barrel EUR. In the past, the average statistics for new wells has been increased by the occasional well that far outperforms the average. To date, we have not encountered any new wells with the higher producing profiles. However, at 30,000 barrels EUR, an initial production rate of 30 Bopd, an average well cost of $406 (increased from the original $360 estimate due to pipe, mud and rig costs increasing in the third quarter) and an oil price of $80 per barrel, these wells have a half life of 5.5 years and will pay for themselves in 2.9 years. Additionally, at September 30, 2008, we had approximately 90% of the current oil production hedged through year end 2008 on costless collars at a floor price of $95.80 per barrel of oil, with the floor price changing to $90 per barrel for January 1, 2009 through April 30, 2013. At $95.80 per barrel of oil, a typical well in the project generates a 55% IRR, and at $90 per barrel, it generates a 46% IRR.

Piceance. Average daily production, net to the Company, in the area was 3,676 Mcfed and 3,095 Mcfed for the three and nine months ended September 30, 2008, respectively, compared to 4,207 Mcfed and 3,076 Mcfed for the same prior year periods. The decrease in production in the three month period ended September 30, 2008, relates entirely to the sale of 50% of our interest in the Piceance property that closed October 1, 2007, significantly offset by the new wells put on production since the sale. The increase in production during the nine month period ended September 30, 2008 is due primarily to the higher number of new wells put on production in 2008, somewhat offset by the sale of half of our 25% working interest in the Piceance Basin non-operated properties in the fourth quarter 2007 and to a lesser extent to the normal production decline of existing wells. 47 gross wells have been spud through September 30, 2008, with 15 new wells hooked up during the third quarter of 2008, bringing the total producing well count to 80 with 28 wells waiting on completion, two wells drilling and three wells completing. Six additional wells have been completed and hooked up since September 30, 2008. Berry has informed us that they intend to drill a total of 52 wells, approximately 6.5 net to our interest, in 2008. During the third quarter 2008, the average new well in the Piceance came on production at 153 Mcfed, net to the Company.

Teton-Noble AMI. As of September 30, 2008 there were 112 producing wells, 10 wells waiting on completion and four waiting on pipeline in our non-operated properties in the Teton-Noble AMI in the DJ Basin. Twenty-one wells were waiting on or in the process of having pumping units installed, which the operator has informed us will increase production and well performance. Production, net to the Company, increased to 737 Mcfed and 612 Mcfed for the three and nine months ended September 30, 2008, respectively, from 185 Mcfed and 94 Mcfed for the same prior year periods. Noble commenced its 2008 drilling program on March 23, 2008, and we were initially informed by the operator that it intended to drill approximately 150 gross wells, approximately 38 net to our interest, during 2008, of which 69 had been spud as of September 30, 2008. We have received and signed AFEs for a total of 105 wells in the Teton-Noble AMI. We have notified the operator of our election to go non-consent on the remaining 2008 drilling program for two reasons: (1) we want time to evaluate the results of adding the pumping units to existing production to bring the production volumes up to economic levels, and (2) we believe it is more prudent to retain the funds that would be expended for additional new wells in this area while we are in these uncertain times of credit and capital market constraints and lower commodity prices. Noble agreed with our approach and has informed us that they will not drill any additional wells in the Teton Noble-AMI in 2008 and until the production issues are resolved. The results of these wells have been disappointing for the amount of investment made to date. The gathering system problems and disappointing production volumes that are being addressed by the operator are resulting in marginal economics for the project, and we intend to exercise our right to go non-consent until the volume-related problems are resolved.

In accordance with generally accepted accounting principles, we recorded an impairment on this property in the quarter ended September 30, 2008 of $4,034. The currently lower than expected production from these wells has resulted in lower reserve estimates being assigned to the wells. At September 30, 2008, the carrying value of the Teton-Noble AMI developed properties exceeded the undiscounted future net revenues estimated to be derived from the wells. As a result, we have determined that $2,267 of capitalized costs (the amount by which the carrying value exceeds the fair value) related to the non-operated properties in the Teton-Noble AMI is impaired, and that amount has been charged to expense in the quarter ended September 30, 2008. The fair value was determined as the discounted net present value of the future cash flows using a 10% discount factor. Additionally, the carrying value of the undeveloped acreage for the Teton-Noble AMI exceeded its fair value by $1,767, and that amount has also been charged to expense in the quarter ended September 30, 2008.

Washco. As of September 30, 2008, there were 27 gross producing wells in the Washco area of the DJ Basin, which we operate, that produced an average of 912 Mcfed and 907 Mcfed, net to the Company, during the three and nine months ended September 30, 2008, respectively. We recognized its first production in the area during the fourth quarter of 2007. We are currently seeking a partner to drill additional wells in the Washco area.

Williston. For the three and nine months ended September 30, 2008, production, net to the Company, in the area averaged 377 Mcfed and 166 Mcfed, respectively, as compared to 37 Mcfed and 40 Mcfed during the same prior year periods. We hold an interest in eight gross wells in the Williston Basin, including seven producing Bakken wells and one Red River well. We have received a permit to drill a Red River well in the Goliath project, located in Williams County, North Dakota. The location is built and waiting on a rig, and we expect the well to spud during the fourth quarter.

On October 7, 2008, we, along with the other partners in the project, signed a participation agreement with Red Technology Alliance LLC (RTA), which gives RTA the option to fund 100% of the drilling, completion and equipping of up to four horizontal Bakken wells in the Williston Basin. Teton owns a 25% working interest in the approximate 80,000 gross acre position. Should RTA elect to drill all four wells, the current working interest owners would retain a collective 60% working interest (Teton would own a 15% working interest) in the project. Halliburton Energy Services Inc. will serve as project manager in the drilling and completion of the initial four wells. The RTA drilling will commence after the spudding of the Red River well noted above.

Oil and Gas Sales

Oil and gas sales increased 642%, from $1,316 for the three months ended September 30, 2007 to $9,765 for the three months ended September 30, 2008, and 571%, from $3,504 for the nine months ended September 30, 2007 to $23,526 for the nine months ended September 30, 2008. The increase in total revenue is due to both increased production volumes, as discussed above by operating area, and an increase in the average price per Mcfe. The average price per

Mcfe increased $8.50 per Mcfe, from $3.23 to $11.73 per Mcfe, and $8.14 per Mcfe, from $4.00 to $12.14 per Mcfe, for the three and nine months ended September 30, 2008, respectively, when compared to the prior year periods. The increases in price per Mcfe is largely impacted by an increase in oil volumes as a percentage of total volumes, as well as higher average spot prices, for both oil and natural gas in 2008 compared to the same periods in 2007. Average commodity prices have decreased significantly at the beginning of the fourth quarter of 2008, with crude oil trading in the $60-70 per barrel range and natural gas trading in the $6.50 per Mcf area (NYMEX) in early October. However, as detailed in the tables below under Liquidity and Capital Resources, *Contractual Obligations,* Teton has in excess of 90% of current oil production hedged at a floor price of $95.80 per barrel and in excess of 60% of current natural gas production hedged at a floor price $9.10 per Mcf (NYMEX) at September 30, 2008.

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LIQUIDITY AND CAPITAL RESOURCES

Historically, our primary sources of liquidity have been cash provided by debt and equity offerings, borrowings under our bank credit facility and sales of interests in our non-operated assets. In the past, these sources have been sufficient to meet the needs of the business and will continue to be utilized as we move forward. As a result of our development drilling program in 2007, the continued development drilling throughout 2008 and the additional producing well count added from the April 2, 2008 acquisition in the Central Kansas Uplift, we expect that cash flow from operating activities will begin to contribute more significantly to our cash requirements for the remainder of 2008 and thereafter. In response to the lower oil and natural gas prices currently being encountered, we intend to further lower our capital expenditure budget for the remainder of 2008 by an additional $5-10 million, from its current level of $40.5 million. We believe that cash on hand and amounts available under our $150 million credit facility ($34.5 million borrowing base at September 30, 2008), together with anticipated net cash provided by operating activities during the remainder of 2008, will provide us with sufficient funds to develop new reserves, maintain our current facilities and complete our revised capital expenditure program through the end of 2008. However, due to the current turbulent economic times, we will evaluate our approach to 2009 capital spending over the course of the fourth quarter of 2008 to determine our initial capital program for 2009. If commodity prices remain at their current levels and capital continues to be as tightly constrained as it currently is, and we believe there is a high likelihood that will be the case, we will set a course for 2009 that restricts capital expenditures to maintenance and new drilling that does not exceed our discretionary cash flow and borrowing base limitations for 2009. Depending on the timing and amount of future projects, we may be required to seek additional sources of capital. While we believe that we would normally be able to secure additional financing if required, we can provide no assurance in the current markets that we will be able to do so or as to the terms of any additional financing.

We also may receive proceeds from the exercise of outstanding warrants and/or options as we did during previous years. At September 30, 2008, warrants to purchase 5,232,651 shares of common stock were outstanding. On October 7, 2008, we entered into a warrant exchange agreement whereby we exchanged 990,000 shares of our common stock for 3,960,000 of the outstanding warrants, leaving 1,272,651 warrants outstanding. These warrants have a weighted average exercise price of $5.52 per share and expire between October 2008 and December 2012. At September 30, 2008, options to purchase 1,415,844 shares of common stock were outstanding. These options have a weighted average exercise price of $3.55 per share and expire between April 2013 and May 2015. During the three and nine months ended September 30, 2008, we received proceeds of approximately $0 and $1,905, respectively, from the exercise of warrants.

Credit Facility

On August 9, 2007, the $50 million revolving credit facility with BNP Paribas (the Credit Facility) was replaced by an amended and restated Credit Facility (the Amended Credit Facility) with JP Morgan Chase Bank, N.A. The Amended Credit Facility had an initial borrowing capacity of $50 million and was amended on April 2, 2008 to a $150 million revolving credit facility ($50 million borrowing base) as a result of adding the additional reserves related to the acquisition of the Central Kansas Uplift properties previously discussed.

In connection with the privately placed 10.75% Secured Convertible Debentures, the borrowing base on our Amended Credit Facility was reduced to $32.5 million. On August 1, 2008 the borrowing base was re-determined and increased to $34.5 million. While there will be a re-determination on November 1, 2008, the Company does not expect to request an additional increase to the borrowing base at this time.

Prior to the 90-day anniversary of the Original Issue Date of our privately placed 10.75% Secured Convertible Debentures (Debentures), the holders elected to exercise their 90-day put option as discussed in Note 5 to the Consolidated Financial Statements. We repaid the $10 million in Secured Convertible Debentures, reducing the total outstanding amount to $30 million. As a result, our total available borrowings under the Debentures and Amended Credit Facility are $64.5 million as of September 30, 2008.

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The following table provides information about our financial position (amounts in thousands, except ratios):

	September 30, 2008		December 31, 2007	
Financial Position Summary				
Cash and cash equivalents	$	2,650	$	24,616
Working capital	$	(7,925)	$	8,259
Debt outstanding	$	55,017	$	9,630
Stockholders equity	$	53,497	$	49,028
Ratios				
Long-term debt to total capital ratio		50.7%		14.0%
Total debt to equity ratio		102.8%		19.6%

At September 30, 2008, we had negative working capital of $7,925, due primarily to cash expenditures during the nine months ended September 30, 2008 for our share of drilling and completion expenses in the non-operated properties of the Piceance Basin and Teton-Noble AMI, and our operated properties in the DJ Basin and the Central Kansas Uplift, and the Central Kansas Uplift acquisition, somewhat offset by normal fluctuations in the outstanding receivable and payable/accrued liability accounts. Additionally, in accordance with SFAS 133, we have recorded $22.5 million of income for unrealized gains on oil and gas derivative contracts, resulting in a significant decrease to our accumulated deficit at September 30, 2008, as compared to June 30, 2008. The accumulated deficit is a component of stockholders equity and is reflected in that line above. The higher outstanding debt balance resulting from our growth in drilling activities and the acquisition of the CKU properties, in turn, results in a much inflated total debt to equity ratio, as noted above. The volatility of the oil and gas commodity prices used to value the unrealized gains (losses) on the related derivative contracts, as required by SFAS No. 133, may continue to increase the volatility of stockholders equity, specifically the accumulated deficit, and that could have a significant effect on the related ratios.

Cash Flows and Capital Requirements

The following table summarizes our cash flows for the periods indicated:

	Nine months ended September 30, 2008		2007	
Cash provided by (used in):				
Operating Activities	$	9,423	$	(1,861)
Investing Activities		(70,857)		(27,203)
Financing Activities		39,468		28,596
Net change in cash	$	(21,966)	$	(468)

During the nine months ended September 30, 2008, net cash provided by operating activities was $9,423 as compared to net cash used in operating activities of $1,861 during the same prior year period. Our net loss increased by $8,950 during the nine months ended September 30, 2008 as compared to the same prior year period. This increase in net loss is due largely to an increase in the unrealized loss on oil and gas derivative contracts, a non-cash item required by SFAS No. 133, of $943; an increase in realized loss on oil and gas derivative contracts of $3,707; an increase in impairment expense, a non-cash item required by SFAS No. 144, related to the Teton-Noble AMI of $4,304, an increase in general and administrative expenses of $6,419 (largely due to an increase in non-cash compensation) and an increase in non-cash interest expense related to the amortization of deferred debt discount and issuance costs of $8,937; and less significantly to an increase in lease operating and related production expenses (due primarily to increased production and production in new locations with higher oil production and resultant per unit LOE that is slightly higher). These increases were somewhat offset by an increase in oil and gas revenues, from $3,504 to $23,526 during the nine months ended September 30, 2008.

During the nine months ended September 30, 2008, net cash used in investing activities was $70,857 as compared to $27,203 in the same prior year period. Cash expenditures during the nine month period ended September 30, 2008 relate largely to the acquisition of producing properties and undeveloped acreage in the Central Kansas Uplift (as previously discussed), as well as development of our non-operated properties in the Piceance Basin and the Teton-Noble AMI, and of our operated properties in the DJ Basin and Central Kansas Uplift. Amounts were funded primarily from borrowings on our Amended Credit Facility, the issuance of our 10.75% Secured Convertible Debentures and cash flow from operating activities.

During the nine months ended September 30, 2008, net cash provided by financing activities was $39,468 as compared to $28,596 in the same prior year period. During the nine months ended September 30, 2008, we repaid the $8.0 million outstanding as of December 31, 2007 under our Amended Credit Facility and repaid $6.6 million of the $9.0 million in Senior Secured Convertible Notes (the remaining $2.4 million converted into common stock prior to maturity). Net borrowings on our Amended Credit Facility were approximately $25 million, and we raised $30 million related to our privately placed 10.75% Secured Convertible Debentures.

Our revised capital budget for 2008 of $30-35 million includes planned drilling in the Central Kansas Uplift of up to 20 wells, the Piceance Basin of up to 52 wells, the DJ Basin non-operated properties of up to 105 wells for which we have received and executed AFEs, and the Williston Basin Red River well. Of that amount approximately $23.3 million has been accrued or expended in the nine months ended September 30, 2008, primarily for our share of drilling and completion expenses in the non-operated properties of the Piceance and Teton-Noble AMI and in our operated property of the Central Kansas Uplift. Our planned 2008 development and exploration expenses could increase if any of the operations associated with our properties experience cost overruns. We currently anticipate that the remaining availability on our Amended Credit Facility and expected cash flow from operations in the fourth quarter of 2008 will be adequate to cover the expected capital expenditures for the fourth quarter.

Contractual Obligations

We have a Company hedging policy in place, to protect a portion of our production against future pricing fluctuations. Our outstanding hedges as of September 30, 2008 are summarized below:

Type of Contract	Remaining Volume	Fixed Price (1)	Price Index (2)	Remaining Period
Oil Fixed Price Swap	5,520	$80.70	WTI	10/01/08-12/31/08
Oil Costless Collar	36,753	$95.80 Floor/$103.00 Ceiling	WTI	10/01/08-12/31/08
Oil Costless Collar	143,545	$90.00 Floor/$104.00 Ceiling	WTI	01/01/09-12/31/09
Oil Costless Collar	106,876	$90.00 Floor/$104.00 Ceiling	WTI	01/01/10-12/31/10
Oil Costless Collar	87,920	$90.00 Floor/$104.00 Ceiling	WTI	01/01/11-12/31/11
Oil Costless Collar	79,611	$90.00 Floor/$104.00 Ceiling	WTI	01/01/12-12/31/12
Oil Costless Collar	25,192	$90.00 Floor/$104.00 Ceiling	WTI	01/01/13-04/30/13
Total Bbl	485,417			
Natural Gas Fixed Price Swap	30,000	$5.78	CIGRM	10/01/08-10/31/08
	184,000	$6.00 Floor/$7.10 Ceiling	CIGRM	10/01/08-12/31/08

Natural Gas Costless Collar				
Natural Gas Costless Collar	62,000	$6.00 Floor/$7.10 Ceiling	CIGRM	01/01/09-01/31/09
Natural Gas Costless Collar	473,867	$6.50 Floor/$7.75 Ceiling	CIGRM	02/01/09-12/31/09
Natural Gas Costless Collar	417,405	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/10-12/31/10
Natural Gas Costless Collar	355,399	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/11-12/31/11
Natural Gas Costless Collar	310,702	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/12-12/31/12
Natural Gas Costless Collar	95,200	$6.50 Floor/$7.75 Ceiling	CIGRM	01/01/13-04/30/13
Natural Gas Costless Collar	26,685	$9.10 Floor/$9.75 Ceiling	NYMEX	10/01/08-12/31/08
Natural Gas Costless Collar	77,630	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/09-12/31/09
Natural Gas Costless Collar	46,274	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/10-12/31/10
Natural Gas Costless Collar	26,158	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/11-12/31/11
Natural Gas Costless Collar	15,258	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/12-12/31/12
Natural Gas Costless Collar	4,104	$9.10 Floor/$9.75 Ceiling	NYMEX	01/01/13-04/30/13
Total MMBtu	2,124,682			

(1) Fixed price is per Bbl for oil swaps and collars and per MMBtu for natural gas swaps and collars.

(2) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platts for Inside FERC on the first business day of each month. NYMEX refers

to quoted prices on the New York Mercantile Exchange. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

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The costless collar hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements to a fixed point. Consequently, while these hedges are designed to decrease our exposure to price decreases while allowing us to share in some upside potential of price increases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the natural gas contracts listed above, a $0.10 hypothetical change in the CIGRM or NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the unrealized gain or loss on hedging activities in 2008 of $212. For the oil contracts listed above, a $1.00 hypothetical change in the WTI price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the unrealized gain or loss on hedging activities in 2008 of $485. The Company plans to continue to evaluate the possibility of entering into derivative contracts, as prices change and additional volumes become available in the future, to decrease exposure to commodity price volatility.

Off Balance Sheet Arrangements

We do not participate in transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities are often referred to as structured finance or special purpose entities (SPEs) or variable interest entities (VIEs). SPEs and VIEs can be established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We were not involved in any unconsolidated SPEs or VIEs at any time during any of the periods presented in this Quarterly Report on Form 10-Q.

RESULTS OF OPERATIONS

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

Sales volume and price comparisons

	Three months ended September 30,					
	2008			2007		
	Volume		Average Price (1)	Volume		Average Price (1)
Product:						
Gas (Mcf)	451,027	$	5.75	401,751	$	3.25
Oil (Bbls)	63,546	$	97.30	948	$	69.43
Mcfe	832,303	$	10.54	407,439	$	3.36

(1) Average price includes the impact of hedging activity.

For the three months ended September 30, 2008, we had net income from continuing operations of $19,304 as compared to a net loss of $952 in the same prior year period. Factors contributing to the $20,256 increase in net income include the following:

Oil and gas production for the three months ended September 30, 2008 increased 104% to 832,303 Mcfe as compared to 407,439 Mcfe in the same prior year period. The increase in production is largely attributable to the recognition of our first production in the Central Kansas Uplift, acquired in April of 2008, and to increased production in the Piceance Basin, Teton-Noble AMI, the Washco operating area and the Williston Basin. Production in the Central Kansas Uplift was 307,648 Mcfe for the three months ended September 30, 2008 (approximately 557 Bopd for the three month period) and is expected to increase throughout the remainder of the year as newly drilled wells are brought on line. As of October 22, 2008, we have spud 17 wells, of which ten have been determined to be economically viable producing wells and two others are being completed as salt water disposal wells. Production in the Piceance decreased to 338,227 Mcfe for the three months ended September 30, 2008, as compared to 387,039 Mcfe for the same prior year period. The decrease is due primarily to, the fact that we sold half of our 25% working interest in the Piceance Basin non-operated properties in the fourth quarter 2007 and, to a lesser extent, the normal production decline of existing wells, somewhat offset by an increase in producing well. Twenty gross wells were spud during the third quarter of 2008 and 15 gross wells were completed and hooked up. During the first three quarters of 2008, 47 of the planned 52 wells have been spud, bringing the total producing well count to 80 wells at September 30, 2008. During the month of July, production was also impacted by a three day field-wide down-time due to compressor maintenance. Production in the Teton-Noble AMI increased

from 17,004 Mcfe for the three months ended September 30, 2007 to 67,824 Mcfe for the three months ended September 30, 2008, due to increased drilling activity. Noble commenced its 2008 drilling program on March 23, 2008, and we were initially informed by the operator that it intended to drill approximately 150 gross wells, approximately 38 net to our interest, during 2008, of which 69 had been spud as of September 30. We have received and signed AFEs for a total of 105 wells in the Teton-Noble AMI. We have notified the operator of our election to go non-consent on the remaining 2008 drilling program for two reasons: (1) we want time to evaluate the results of adding the pumping units to existing production to bring the production volumes up to economic levels, and (2) we believe it is more prudent to retain the funds that would be expended for additional new wells in this area while we are in these times of credit and capital market constraints and lower commodity prices. Noble agreed with our approach and has informed us that they will not drill any additional wells in the Teton Noble-AMI in 2008 and until the production issues are resolved. The results of these wells have been disappointing for the amount of investment made to date. The gathering system problems that are being addressed by the operator are resulting in marginal economics for the project, and we intend to exercise our right to go non-consent until the volume-related problems are resolved.
Washco production for the three months ended September 30, 2008 was 83,945 Mcfe. We recognized our first production in Washco during the fourth quarter of 2007. Williston Basin production increased to 34,659 Mcfe for the three months ended September 30, 2008, from 3,396 Mcfe for the same prior year period. We and our partners have received a permit to drill a Red River well on our acreage in the Goliath project, and the location is built and waiting for a rig. It is anticipated that Red Technology Alliance LLC will spud a Bakken test within 90 days of the spudding of the Red River well. At September 30, 2008, we hold an interest in eight gross wells in the Williston Basin, including seven producing Bakken wells and one Red River well. We have received a permit to drill a Red River well in the Goliath project, located in Williams County, North Dakota. The location is built and waiting on a rig, and we expect the well to spud during the fourth quarter 2008.

Oil and gas sales increased 642% from $1,316 for the three months ended September 30, 2007 to $9,765 for the three months ended September 30, 2008. The increase in total revenue is due to both increased production volumes, as discussed above by operating area, and an increase in the average price per Mcfe. The average price per Mcfe increased $7.18 per Mcfe, from $3.36 to $10.54 per Mcfe, after the effect of hedging gains/losses. We added significant oil production during 2008 as a part of the acquisition in the Central Kansas Uplift. When converted to a per Mcfe basis, oil prices are currently significantly higher than that of natural gas, further contributing to an increase in our price per Mcfe over the same prior year period.

Oil and gas production expenses

	Three Months Ended September 30, 2008	2007
	(in dollars per Mcfe)	
Average price	$ 10.54	$ 3.36
Production costs	2.60	0.98
Production taxes	1.32	0.25
Total operating costs	3.92	1.23
Gross margin before DD&A	$ 6.62	$ 2.13
Gross margin percentage	63%	63%

Our production costs (lease operating expenses and transportation costs) and production taxes for the three months ended September 30, 2008 increased $2,761, due primarily to adding new operating areas and to increased production as discussed above. LOE per Mcfe increased from $1.62 to $2.60 per Mcfe primarily due to the addition of new operating areas with higher oil production which results in higher per unit LOE costs, as well as an increase in transportation costs related to oil in the Central Kansas Uplift. Production taxes increased from $0.25 per Mcfe to $1.32 per Mcfe. The increase is due to increased production in areas with higher production tax rates, as well as to adjustments in the current year for prior period ad valorem taxes.

General and administrative expenses increased $1,904, from $1,766 to $3,670 for the three months ended September 30, 2008. The increase is due primarily to an increase in head count and related cash compensation and employee benefits ($1,371) and non-cash compensation expenses ($1,265) largely related to restricted stock awards for new employees, as well as presumed vesting the third tranche of the 2006 LTIP and second tranche of the 2007 LTIP. These increases were partially offset by a decrease in professional fees of $425 related to the use of financial consultants who have been replaced with additional full-time headcount and an increase in billable G&A costs of $375. There were no other individually significant increases or decreases.

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Depletion, depreciation and amortization expense related to oil and gas properties increased from $1,444 for the three months ended September 30, 2007 to $4,739 for the three months ended September 30, 2008. This increase is due primarily to the increased production, new productive areas and higher capitalized costs over the same prior year period. The Company-wide DD&A rate for the three months ended September 30, 2008 was $5.70 per Mcfe. The Company-wide DD&A rate was inflated, partially by the DD&A rate for the Teton-Noble AMI. The impairment on this property in the quarter ended September 30, 2008 of $4,034 has the effect of reducing the overall DD&A rate on the property and by effect, the overall Company DD&A rate to $5.45 per Mcfe. The Company s properties in the Williston Basin also have inflated DD&A rates due to the reserve values currently estimated for these properties. We expect the rate on these properties to decline as reserves are added based on the success of future wells to be drilled.

On October 7, 2008, we, along with the other partners in the project, signed a participation agreement with Red Technology Alliance LLC (RTA), which gives RTA the option to fund 100% of the drilling, completion and equipping of up to four horizontal Bakken wells in the Williston Basin. Teton owns a 25% working interest in the approximate 80,000 gross acre position. Should RTA elect to drill all four wells, the current working interest owners would retain a collective 60% working interest (Teton would own a 15% working interest) in the project. Halliburton Energy Services Inc. will serve as project manager in the drilling and completion of the initial four wells. The RTA drilling will commence after the spudding of the Red River well noted above.

During the three months ended September 30, 2008, we recorded a net unrealized gain (non-cash) on derivative contracts of $22,465. The gain represents marking the derivative contracts to market at September 30, 2008, based on the future expected prices of the related commodities (see discussion on fair value measurement above).

Net interest expense for the three months ended September 30, 2008 was $1,677 and included $130 of amortization of debt issuance costs related to net borrowings on our Amended Credit Facility and the 10.75% Secured Convertible Notes outstanding during the quarter.

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

Sales volume and price comparisons

	Nine months ended September 30,			
	2008		2007	
	Volume	Average Price (1)	Volume	Average Price (1)
Product:				
Gas (Mcf)	1,120,654	$ 6.56	856,513	$ 4.10
Oil (Bbls)	136,267	$ 97.22	3,320	$ 58.39
Mcfe	1,938,256	$ 10.63	876,433	$ 4.23

(1) Average price includes the impact of hedging activity.

For the nine months ended September 30, 2008, we had a net loss from continuing operations of $18,948 as compared to $9,998 in the same prior year period. Factors contributing to the $8,950 increase in net loss include the following:

Oil and gas production for the nine months ended September 30, 2008 increased 121% to 1,938,256 Mcfe as compared to 876,433 Mcfe in the same prior year period. The increase in production is largely attributable to the recognition of our first production in the Central Kansas Uplift, acquired in April of 2008, and to increased production in the Piceance Basin, the Teton-Noble AMI, the Washco operating area and the Williston Basin. Production in the Central Kansas Uplift was 628,616 Mcfe for the nine months ended September 30, 2008 and is expected to increase throughout the remainder of the year as additional newly drilled wells are brought on line. As of October 22, 2008, we have spud 17 wells, of which ten have been determined to be economically viable producing wells and two others are being completed as salt water disposal wells. Production in the Piceance increased to 848,095 Mcfe for the nine months ended September 30, 2008 as compared to 839,844 Mcfe for the same prior year period. The increase is due primarily to an increase in producing well count offset largely by the fact that we sold half of our 25% working interest in the Piceance Basin in the fourth quarter 2007, and, to a lesser extent, by the normal production decline of existing wells. 47 of the 52 planned 2008 wells have been spud, with 28 wells waiting on completion, two wells drilling and three wells completing. There were a total of 80 producing wells at September 30, 2008. During the month of July, production was impacted by a three day field-wide down-time due to compressor maintenance. Production in the Teton-Noble AMI increased from 25,765 Mcfe for the nine months ended September 30, 2007 to 167,695 Mcfe for the nine months ended September 30, 2008, due to increased drilling activity. Noble commenced its 2008 drilling program on March 23, 2008, and we were initially informed by the operator that it intended to drill approximately 150 gross wells, approximately 38 net to our interest, during 2008, of which 69 had been spud as of September 30. We have received and signed AFEs for a total of 105 wells in the Teton-Noble AMI. We have notified the operator of our election to go non-consent on the remaining 2008 drilling program for two reasons: (1) we want time to evaluate the results of adding the pumping units to existing production to bring the production volumes up to economic levels, and (2) we believe it is more prudent to retain the funds that would be expended for additional new wells in this area while we are in these times of credit and capital market constraints and lower commodity prices. Noble agreed with our approach and has informed us that they will not drill any additional wells in the Teton Noble-AMI in 2008 and until the production issues are resolved. The results of these wells have been disappointing for the amount of investment made to date. The gathering system problems that are being addressed by the operator are resulting in marginal economics for the project, and we intend to exercise our right to go non-consent until the volume-related problems are resolved. Washco production for the nine months ended September 30, 2008 was 248,408 Mcfe. We recognized our first production in the area during the fourth quarter of 2007. Williston Basin production increased to 45,442 Mcfe for the nine months ended September 30, 2008, from 10,824 Mcfe for the same prior year period. It is anticipated that Red Technology Alliance LLC will spud a Bakken test within 90 days of the spudding of the Red River well. At September 30, 2008, we hold an interest in eight gross wells in the Williston Basin, including seven producing Bakken wells and one Red River well. We have received a permit to drill a Red River well in the Goliath project, located in Williams County, North Dakota. The location is built and waiting on a rig, and we expect the well to spud during the fourth quarter.

Oil and gas sales increased 571% from $3,504 for the nine months ended September 30, 2007 to $23,526 for the nine months ended September 30, 2008. The increase in total revenue is due to both increased production volumes, as discussed above by operating area, and an increase in the average price per Mcfe. The average price per Mcfe increased $6.40 per Mcfe, from $4.23 to $10.63 per Mcfe, after the effect of hedging gains/losses. More typical winter weather and lower average natural gas storage volumes combined to produce higher average prices for natural gas in 2008 compared to 2007. Additionally, we added significant oil production during the second quarter of 2008 as a part of the acquisition in the Central Kansas Uplift. When converted to a per Mcfe basis, oil prices are currently significantly higher than that of natural gas, also contributing to an increase in our price per Mcfe over the same prior year period.

Oil and gas production expenses

	Nine Months Ended September 30,	
	2008	2007
	(in dollars per Mcfe)	
Average price	$ 10.63	$ 4.23
Production costs	2.28	0.90
Production taxes	0.89	0.29
Total operating costs	3.17	1.19
Gross margin before DD&A	$ 7.46	$ 3.04
Gross margin percentage	70%	72%

Our production costs (lease operating expenses and transportation costs) and production taxes for the nine month ended September 30, 2008 increased $5,094, due primarily to adding new operating areas and to increased production as discussed above. LOE per Mcfe increased from $0.90 to $2.28 per Mcfe primarily due to the addition of new operating areas with higher oil production which results in higher per unit LOE costs, as well as an increase in transportation costs related to oil in the Central Kansas Uplift. Production taxes increased from $0.29 per Mcfe to $0.89 per Mcfe. The increase is due to increased production in areas with higher production tax rates, as well as to adjustments in the current year for prior period ad valorem taxes.

General and administrative expenses increased $6,419, from $5,826 to $12,245 for the nine months ended September 30, 2008. The increase is due primarily to an increase in compensation expense related to (1) cash compensation and employee benefits related to additional headcount over the same prior year period ($2,258) and (2) the increase in non-cash compensation charges ($4,709) for presumed vesting of 2006 and 2007 LTIP and restricted stock awards, and the actual vesting of the 2007 LTIP awards and 2008 LTIP Tranche 1 awards at June 30, 2008. These increases were partially offset by an increase in billable G&A of $1,147. There were no other individually significant increases or decreases.

Depletion, depreciation and amortization expense related to oil and gas properties increased from $2,582 for the nine months ended September 30, 2007 to $10,044 for the nine months ended September 30, 2008. This increase is due primarily to the increased production, new productive areas and higher capitalized costs over the same prior year period. The Company-wide DD&A rate for the nine months ended September 30, 2008 was $5.19 per Mcfe. The Company-wide DD&A rate was inflated, partially by the DD&A rate for the Teton-Noble AMI. The impairment on this property in the quarter ended September 30, 2008 of $4,034 has the effect of reducing the overall DD&A rate on the property and by effect, the overall Company DD&A rate, to $5.08 per Mcfe. The Company s properties in the Williston Basin also have inflated DD&A rates due to the reserve values currently estimated for these properties. We expect the rate on these properties to decline as reserves are added based on the success of future wells to be drilled.

On October 7, 2008, we, along with the other partners in the project, signed a participation agreement with Red Technology Alliance LLC (RTA), which gives RTA the option to fund 100% of the drilling, completion and equipping of up to four horizontal Bakken wells in the Williston Basin. Teton owns a 25% working interest in the approximate 80,000 gross acre position. Should RTA elect to drill all four wells, the current working interest owners would retain a collective 60% working interest (Teton would own a 15% working interest) in the project. Halliburton Energy Services Inc. will serve as project manager in the drilling and completion of the initial four wells. The RTA drilling will commence after the spudding of the Red River well noted above.

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During the nine months ended September 30, 2008, we recorded a net unrealized loss (non-cash) on derivative contracts of $1,014. The loss represents marking the derivative contracts to market at September 30, 2008, based on the future expected prices of the related commodities (see discussion on fair value measurement above).

Net interest expense for the nine months ended September 30, 2008 was $11,311 and included $7,370 and $1,419 of amortization of debt issuance discount and debt issuance costs (non-cash), respectively, related to the 8% Senior Subordinated Convertible Notes and $148 of amortization of debt issuance costs related to the 10.75% Secured Convertible Debentures. The remaining interest expense relates to net borrowings on our Amended Credit Facility and the convertible notes that were outstanding during the nine months ended September 30, 2008.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

On January 1, 2008, we adopted the provisions of SFAS No. 157, Fair Value Measurements (SFAS No. 157) related to assets and liabilities, which primarily affect the valuation of our derivative contracts (see Note 4). In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13, which removes certain leasing transactions from the scope of SFAS No. 157, and FSP FAS 157-2, Effective Date of FASB Statement No. 157, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. Beginning January 1, 2009, we will adopt the provisions for nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis. The adoption of SFAS No. 157 did not have a material effect on our financial condition or results of operations. We do not believe that the implementation of this standard, with respect to its effect on nonfinancial assets and liabilities, will have a material impact on our consolidated financial position or results of operations.

On January 1, 2008, we adopted the provision of SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159) which permits an entity to measure certain financial assets and financial liabilities at fair value. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. The adoption of SFAS No. 159 did not have a material effect on our financial condition or results of operations as we did not make any such elections under this fair value option.

In October 2008, the FASB issued FSP 157-3 Determining Fair Value of a Financial Asset in a Market That Is Not Active (FSP 157-3). FSP 157-3 clarifies the application of SFAS No. 157 in inactive markets. FSP 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued. The implementation of FSP 157-3 did not have a material impact on our consolidated financial position or results of operations.

New accounting pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS No. 141R will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS No. 141R requires the acquiring Company to measure almost all assets acquired and liabilities assumed in the acquisition at fair value as of the acquisition date. SFAS No. 141R is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied prospectively with the exception of income taxes which should be applied retrospectively for all business combinations. Early adoption is prohibited. We are in the process of evaluating the impacts, if any, of adopting this pronouncement.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, (SFAS No. 161), an amendment to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. SFAS No. 161 requires enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. This Statement will be effective for our interim and annual financial statements beginning in fiscal year 2010. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. We are in the process of evaluating the impacts, if any, of adopting this pronouncement.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS No. 162). SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements presented in conformity with GAAP. SFAS No. 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board (the PCAOB) amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We do not believe that the implementation of this standard will have a material impact on our consolidated financial position or results of operations.

In May 2008, the FASB issued FSP No. APB 14-1, Accounting for Convertible Debt Instruments that May Be Settled in Cash upon Conversion (Including Partial Cash Settlement), (FSP APB 14-1). FSP APB 14-1 addresses the accounting for convertible debt securities that, upon conversion, may be settled by the issuer either fully or partially in cash. FSP APB 14-1 is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied retrospectively to all past period presented. Early adoption is prohibited. We are in the process of evaluating the impacts, if any, of adopting this FSP.

In June 2008, the FASB issued FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 clarified that all outstanding unvested share-based payment awards that contain rights to non-forfeitable dividends participate in undistributed earnings with common shareholders. Awards of this nature are considered participating securities and the two-class method of computing basic and diluted earnings per share must be applied. FSP EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. We do not believe that the implementation of this standard will have a material impact on its consolidated financial position or results of operations. At this time, no such instruments exist for our Company.

In June 2008, the FASB ratified the consensus reached by the Task Force, EITF Issue No. 07-5, Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity s Own Stock (EITF 07-5). EITF 07-5 addresses how an entity should evaluate whether an instrument is indexed to its own stock. The consensus is effective for fiscal years (and interim periods) beginning after December 15, 2008 (fiscal 2009 for the Company). The consensus must be applied to outstanding instruments as of the beginning of the fiscal year in which the consensus is adopted and should be treated as a cumulative-effect adjustment to the opening balance of retained earnings. Early adoption is not permitted. We are in the process of evaluating the impacts, if any, of adopting this EITF.

In June 2008, the FASB issued EITF 08-4, Transition Guidance for Conforming Changes to Issue No. 98-5 (EITF 08-4). EITF 08-4 provides transition guidance with respect to conforming changes made to EITF 98-5, that result from EITF 00-27, Application of Issue No. 98-5 to Certain Convertible Instruments , and SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity . EITF 08-4 is effective for fiscal years ending after December 15, 2008. Early adoption is permitted. We are in the process of evaluating the impacts, if any, of adopting this EITF.

In September 2008, the FASB ratified EITF Issue No. 08-5, Issuer s Accounting for Liabilities Measured at Fair Value With a Third-Party Credit Enhancement (EITF 08-5). EITF 08-5 provides guidance for measuring liabilities issued with an attached third-party credit enhancement (such as a guarantee). It clarifies that the issuer of a liability with a third-party credit enhancement (such as a guarantee) should not include the effect of the credit enhancement in the fair value measurement of the liability. EITF 08-5 is effective for the first reporting period beginning after December 15, 2008. We are in the process of evaluating the impacts, if any, of adopting this EITF.

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FAIR VALUE MEASUREMENT

Effective January 1, 2008, we adopted the provisions of SFAS No. 157 for all financial instruments. The valuation techniques required by SFAS No. 157 are based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent resources, while unobservable inputs reflect our market assumptions. The standard established the following fair value hierarchy:

Level 1 Quoted prices for identical assets or liabilities in active markets.

Level 2 Quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; and model-derived valuations whose inputs or significant value drivers are observable.

Level 3 Significant inputs to the valuation model are unobservable.

The following describes the valuation methodologies we use to measure financial instruments at fair value.

Debt and Equity Securities

The recorded value of our long-term debt approximates its fair value as it bears interest at a floating rate. Our Secured Convertible Notes (Convertible Notes) were a negotiated instrument and are therefore recorded at fair value. We evaluated the Convertible Notes and determined that there were no embedded features which would require derivative accounting.

Derivative Instruments

We use derivative financial instruments to mitigate exposures to oil and gas production cash flow risks caused by fluctuating commodity prices. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as liabilities or assets on the balance sheet. For oil and gas derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in the consolidated statement of operations. When oil and gas derivative contracts are settled, we recognizes realized gains and losses under the other income and expense caption in its consolidated statement of operations. At September 30, 2008, we did not have any derivative contracts that qualify as cash flow hedges.

Derivative assets and liabilities included in Level 2 include fixed rate swap arrangements for the sale of oil and natural gas and hedge contracts, valued using the Black-Scholes-Merton valuation technique, in place through 2013 for a total of approximately 485,417 Bbls of oil production and 2,124,682 MMbtu of natural gas production.

We also use various types of financing arrangements to fund our business capital requirements, including convertible debt and other financial instruments indexed to the market price of our common stock. We evaluate these contracts to determine whether derivative features embedded in host contracts require bifurcation and fair value measurement or, in the case of free-standing derivatives (principally warrants), whether certain conditions for equity classification have been achieved. In instances where derivative financial instruments require liability classification, we initially and subsequently measure such instruments at estimated fair value using Level 2 inputs. Accordingly, we adjust the estimated fair value of these derivative components at each reporting period through earnings until such time as the instruments are exercised, expired or permitted to be classified in stockholders equity.

As of September 30, 2008, the fair value of financing warrants included as a component of current liabilities consisted of warrants to purchase 3,600,000 shares of our common stock that do not achieve all of the requisite conditions for equity classification. These free-standing derivative financial instruments arose in connection with our financing transaction in May 2007 which consisted of the $9.0 million Convertible Notes and warrants to purchase 3,600,000 shares of our common stock at a $5.00 strike price for a period of five years (with a cashless exercise option). Efffective October 7, 2008, we and all of the investors that held the 3,600,000 warrants agreed to exchange the warrants for 900,000 shares of the Company s common stock. We determined that this transaction constituted a Type I subsequent event, indicative of a condition that existed as of September 30, 2008 and as a result, the carrying value of the current liability for the financing warrants was reduced to the fair value at the date of exchange as more fully discussed in Note 5.

On April 2, 2008, in conjunction with the purchase of production and reserves related to certain oil and gas producing properties in the Central Kansas Uplift, we issued 625,000 warrants to acquire shares of our common stock. Each warrant is exercisable on or after July 2, 2008 at an exercise price of $6.00 per share, and expires on April 1, 2010. We evaluated these instruments in accordance with SFAS No. 133 and EITF 00-19 and determined, based on the facts and circumstances, that these instruments qualify for classification in stockholders equity and therefore are not reported as a liability or measured at fair value on a recurring basis.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in nature gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future gains or losses, but rather indicators of reasonably possible gains or losses depending on market dynamics. This forward-looking information provides indicators of how we view and manage (or anticipate managing) our ongoing market risk exposures.

Commodity Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas commodity prices have been volatile and unpredictable for several years. The prices we receive for our production depend on numerous factors beyond our control. Based on our production for the nine months ended September 30, 2008, our income before income taxes for the period would have moved up or down approximately $32 for every $1.00 change in oil prices and $28 for every $0.10 change in natural gas prices.

We have entered into derivative contracts to manage our exposure to oil and natural gas price volatility. We have a Company hedging policy in place to protect a portion of our production against future price fluctuations. Refer to Contractual Obligations above for a breakout of our outstanding hedge positions at September 30, 2008.

Interest Rate Risk

At September 30, 2008, we had $25,017 outstanding on our Credit Facility. Under the Amended Credit Facility, each loan bears interest at a Eurodollar rate (London Interbank Offered Rate, or LIBOR) plus applicable margins of 1.25% to 2.25% or a base rate (the higher of the Prime Rate or the Federal Funds Rate plus 0.5%) plus applicable margins of 0% to .75%, at our request. We are also required to pay a commitment fee of 0.375% or 0.5% per annum, based on the average daily amount of the unused amount of the commitment. Based on the $25,017 outstanding under our Credit Facility at September 30, 2008, a one hundred basis point (1.0%) increase in each of the average LIBOR rate and federal funds rate would result in an additional interest expense to us of approximately $63 per quarter.

ITEM 4. CONTROLS AND PROCEDURES

In accordance with the Securities Exchange Act of 1934, as amended, Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that as of September 30, 2008, our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

There has been no change in our internal control over financial reporting that occurred during the quarter ended September 30, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are not a party to any legal proceedings.

ITEM 1A. RISK FACTORS

The following is the only material change in our Risk Factors from those reported in Item 1A of Part I of our 2007 Annual Report on From 10-K filed with the Securities and Exchange Commission on March 13, 2008.

Recent economic trends could adversely affect our financial performance.

As widely reported, the global financial markets have been experiencing extreme disruption in recent months, including severely diminished liquidity and credit availability. Concurrently, economic weakness has begun to accelerate globally. We believe these conditions have not materially impacted our financial position as of September 30, 2008 or liquidity for the nine months ended September 30, 2008. However, our financial condition and performance could be negatively impacted if either of these conditions exists for a sustained period of time, or if there is further deterioration in financial markets and major economies. We are unable to predict the likely duration and severity of the current disruption in financial markets and adverse economic conditions in the U.S. and the world.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.
None.
ITEM 3. DEFAULTS UPON SENIOR SECURITIES.
None.
ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.
No matters were submitted to a vote of our security holders during the third quarter of 2008.
ITEM 5. OTHER INFORMATION.
On October 31, 2008, the Compensation Committee of Teton s Board of Directors voted to add certain clarifying language and changes to the employment agreements with key officers by removing the sixty day window directly before the renewal of the agreement which allowed the executive or the Company to terminate the agreement.
ITEM 6. EXHIBITS
The following exhibits are filed as part of this report:
Exhibit Number and Description:

3.1.1 Certificate of Incorporation of EQ Resources Ltd., incorporated by reference to Exhibit 2.1.1 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.2 Certificate of Domestication of EQ Resources Ltd., incorporated by reference to Exhibit 2.1.2 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.3 Articles of Merger of EQ Resources Ltd. and American-Tyumen Exploration Company, incorporated by reference to Exhibit 2.1.3 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.4 Certificate of Amendment of Teton Petroleum Company, incorporated by reference to Exhibit 2.1.4 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.5 Certificate of Amendment of Teton Petroleum Company, incorporated by reference to Exhibit 2.1.5 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.6 Certificate of Amendment to Certificate of Incorporation, dated June 28, 2005, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 15, 2005.

3.2 Bylaws, as amended, of Teton Petroleum Company, incorporated by reference to Exhibit 3.2 of Teton s Form 10-QSB, filed on August 20, 2002.

4.1 Secured Subordinated Convertible Debenture Indenture dated September 19, 2008 among Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on September 23, 2008).

4.2 Form of 10.75% Secured Convertible Debenture dated June 18, 2008 issued by Teton Energy Corporation (incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.3 Form of Global 10.75% Secured Subordinated Convertible Debenture (included in Exhibit 4.1).

4.4	Form of Securities Purchase Agreement dated June 9, 2008, entered into by and between Teton Energy Corporation and the investors (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.5	Letter Agreement dated September 19, 2008 amending and supplementing the Securities Purchase Agreement dated June 9, 2008 (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on September 23, 2008).
4.6	Form of Registration Rights Agreement (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.7	Subordinated Guaranty and Pledge Agreement dated June 18, 2008, entered into by and between Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and Whitebox Advisors LLC (incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.8	Form of Amended and Restated Subordinated Guaranty and Pledge Agreement dated September 19, 2008 (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on September 23, 2008).
4.9	Form of Intercreditor and Subordination Agreement dated June 9, 2008, entered into by and between, Teton Energy Corporation, JPMorgan Chase Bank, N.A. as administrative agent and the representative for the subordinated holders (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.10	Amended and Restated Intercreditor and Subordination Agreement dated September 19, 2008 (incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed with the SEC on September 23, 2008).
10.1	Warrant Exchange Agreement by and between Teton Energy Corporation and the Investors, dated October 4, 2008 and fully executed on October 7, 2008 (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on October 14, 2008).
31.1	Certification by Chief Executive Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
31.2	Certification by Chief Financial Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
32	Certification by Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, filed herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TETON ENERGY CORPORATION
(Registrant)

Date: November 6, 2008

By: /s/ Karl F. Arleth
Karl F. Arleth
President and Chief Executive Officer

Date: November 6, 2008	By: /s/ Lonnie R. Brock Lonnie R. Brock Executive Vice President and Chief Financial Officer (principal financial and accounting officer)

EXHIBIT INDEX

Exhibit Number and Description:

3.1.1 Certificate of Incorporation of EQ Resources Ltd., incorporated by reference to Exhibit 2.1.1 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.2 Certificate of Domestication of EQ Resources Ltd., incorporated by reference to Exhibit 2.1.2 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.3 Articles of Merger of EQ Resources Ltd. and American-Tyumen Exploration Company, incorporated by reference to Exhibit 2.1.3 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.4 Certificate of Amendment of Teton Petroleum Company, incorporated by reference to Exhibit 2.1.4 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.5 Certificate of Amendment of Teton Petroleum Company, incorporated by reference to Exhibit 2.1.5 of Teton s Form 10-SB (File No. 000-31170), filed on July 3, 2001.

3.1.6 Certificate of Amendment to Certificate of Incorporation, dated June 28, 2005, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 15, 2005.

3.2 Bylaws, as amended, of Teton Petroleum Company, incorporated by reference to Exhibit 3.2 of Teton s Form 10-QSB, filed on August 20, 2002.

4.1 Secured Subordinated Convertible Debenture Indenture dated September 19, 2008 among Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on September 23, 2008).

4.2 Form of 10.75% Secured Convertible Debenture dated June 18, 2008 issued by Teton Energy Corporation (incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.3 Form of Global 10.75% Secured Subordinated Convertible Debenture (included in Exhibit 4.1).

4.4 Form of Securities Purchase Agreement dated June 9, 2008, entered into by and between Teton Energy Corporation and the investors (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.5 Letter Agreement dated September 19, 2008 amending and supplementing the Securities Purchase Agreement dated June 9, 2008 (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on September 23, 2008).

4.6 Form of Registration Rights Agreement (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.7 Subordinated Guaranty and Pledge Agreement dated June 18, 2008, entered into by and between Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and Whitebox Advisors LLC (incorporated by reference to

Exhibit 10.4 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.8 Form of Amended and Restated Subordinated Guaranty and Pledge Agreement dated September 19, 2008 (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on September 23, 2008).

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4.9 Form of Intercreditor and Subordination Agreement dated June 9, 2008, entered into by and between, Teton Energy Corporation, JPMorgan Chase Bank, N.A. as administrative agent and the representative for the subordinated holders (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on June 19, 2008).

4.10 Amended and Restated Intercreditor and Subordination Agreement dated September 19, 2008 (incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed with the SEC on September 23, 2008).

10.1 Warrant Exchange Agreement by and between Teton Energy Corporation and the Investors, dated October 4, 2008 and fully executed on October 7, 2008 (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on October 14, 2008).

31.1 Certification by Chief Executive Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.

31.2 Certification by Chief Financial Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.

32 Certification by Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, filed herewith.