TETON ENERGY CORP
Form 10-Q
August 14, 2007

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U.S. 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 the Quarterly Period Ended June 30, 2007

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

For the transition period from __________ to __________

Commission file number: 001-31679
TETON ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	**84-1482290**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
410 17th Street Suite 1850 Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

(303) 565-4600
(Registrant s telephone number, including area code)

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

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

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

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

As of August 13, 2007, 17,148,372 shares of the issuer s common stock were outstanding.

TETON ENERGY CORPORATION AND SUBSIDIARIES

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Part 1. FINANCIAL INFORMATION
Item 1. Consolidated Financial Statements
TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets

	June 30, 2007 (Unaudited)	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 4,039,616	$ 4,324,784
Trade accounts receivable	920,161	860,070
Advances to operator		401,491
Tubular inventory	148,628	148,628
Fair value of derivatives	205,220	402,867
Prepaid expenses and other assets	183,941	142,163
Debt issuance costs net of amortization of $31,380	1,701,430	
Total current assets	7,198,996	6,280,003
Non-current assets:		
Oil and gas properties (using successful efforts method of accounting)		
Proved	19,874,816	11,635,699
Producing facilities	3,107,667	690,244
Unproved	14,693,970	13,959,480
Wells in progress	12,786,573	8,492,150
Facilities in progress	2,650,518	1,363,644
Land	306,000	300,000
Fixed assets	251,273	242,691
Total property and equipment	53,670,817	36,683,908
Less accumulated depreciation and depletion	(3,040,443)	(1,911,889)
Net property and equipment	50,630,374	34,772,019
Debt issuance costs net	209,335	191,685
Total non-current assets	50,839,709	34,963,704
Total assets	$ 58,038,705	$ 41,243,707
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 6,305,095	$ 1,506,873
Accrued liabilities	2,019,821	4,195,674
Accrued payroll	86,663	890,877
Accrued franchise taxes payable	41,198	30,518
Accrued purchase consideration		775,054

8% senior subordinated convertible notes, net of discount of $8,836,999	163,001	
Derivative contract liabilities	11,527,200	
Total current liabilities	20,142,978	7,398,996
Long term liabilities		
Long term debt senior secured bank debt	6,000,000	
Asset retirement obligations	239,476	78,115
Total long term liabilities	6,239,476	78,115
Total liabilities	26,382,454	7,477,111
Commitments		
Stockholders equity		
Common stock, $0.001 par value, 250,000,000 shares authorized, 16,184,312 and 15,180,649 shares issued and outstanding at June 30, 2007 and December 31, 2006, respectively	16,184	15,180
Additional paid in capital	65,979,000	60,836,839
Stock based compensation	4,931,175	3,138,772
Accumulated deficit	(39,270,108)	(30,224,195)
Total stockholders equity	31,656,251	33,766,596
Total liabilities and stockholders equity	$ 58,038,705	$ 41,243,707

See notes to unaudited consolidated financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations and Comprehensive Loss
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	2006	2007	2006
Oil and gas sales	$ 832,943	$ 650,234	$ 1,901,284	$ 940,483
Cost of sales and expenses:				
Lease operating expense	64,388	114,410	107,281	148,198
Production taxes	89,306	11,832	153,306	19,850
General and administrative	2,180,291	1,705,942	4,059,639	3,048,745
Depreciation, depletion and amortization	581,288	330,173	1,128,554	425,939
Accretion expense from asset retirement obligations	12,769		20,376	
Exploration expense	308,668	74,745	614,802	215,262
Total cost of sales and expenses	3,236,710	2,237,102	6,083,958	3,857,994
Loss from operations	(2,403,767)	(1,586,868)	(4,182,674)	(2,917,511)
Other income (expense):				
Realized gain on natural gas derivative contract	201,000		255,900	
Unrealized loss on natural gas derivative contracts	(104,761)		(197,647)	
Loss on derivative liabilities	(4,629,390)		(4,629,390)	
Interest income	25,137	60,523	54,118	128,540
Interest expense	(333,186)		(346,220)	
Total other income (expense)	(4,841,200)	60,523	(4,863,239)	128,540
Net loss applicable to common shares	$ (7,244,967)	$ (1,526,345)	$ (9,045,913)	$ (2,788,971)
Basic and diluted weighted average common shares outstanding	16,125,492	12,017,214	15,846,748	11,821,760
Basic and diluted loss per common share	$ (0.45)	$ (0.13)	$ (0.57)	$ (0.24)

See notes to unaudited consolidated financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(Unaudited)

	For the Six Months Ended June 30, 2007	For the Six Months Ended June 30, 2006
Cash flows from operating activities		
Net loss	$ (9,045,913)	$ (2,788,971)
Adjustments to reconcile net loss to net cash used in operating activities		
Depreciation and depletion	1,128,554	425,939
Debt issuance cost amortization	57,448	
Accretion expense from asset retirement obligations	20,376	
Accrued stock based compensation net of stock returned	1,792,403	1,038,513
Non-cash loss on derivative liabilities	4,629,390	
Unrealized loss-natural gas derivative contracts	197,647	
Accretion of debt discount on 8% senior subordinated convertible notes	163,001	
Changes in assets and liabilities		
Discontinued operations		(255,000)
Trade accounts receivable	50,809	(284,511)
Advances to operator		(3,321)
Prepaid expenses and other current assets	(41,778)	(57,949)
Accounts payable and accrued liabilities	223,499	497,324
Accrued payroll and franchise taxes payable	(793,534)	26,328
	7,427,815	1,387,323
Net cash used in operating activities	(1,618,098)	(1,401,648)
Cash flows from investing activities		
Proceeds from sale of oil and gas properties		2,700,000
Purchase of fixed assets	(8,582)	(103,050)
Development of oil and gas properties	(14,933,234)	(7,037,981)
Net cash used in investing activities	(14,941,816)	(4,441,031)
Cash flows from financing activities		
Proceeds from exercise of warrants and issuance of stock	2,018,755	4,108,756
Proceeds from 8% senior subordinated convertible notes	9,000,000	
Borrowings from senior bank credit facility	6,000,000	
Debt issuance costs from bank debt and 8% senior subordinated convertible notes	(744,009)	(190,328)
Net cash provided by financing activities	16,274,746	3,918,428
Net decrease in cash and cash equivalents	(285,168)	(1,924,251)
Cash and cash equivalents beginning of year	4,324,784	7,064,295

Cash and cash equivalents end of period	$ 4,039,616	$ 5,140,044
Supplemental disclosure of non-cash activity:		
Accrued stock based compensation	$ 1,792,403	$ 1,196,013
Reduction in accounting service fees	$	$ (157,500)
Deposit applied to oil and gas properties Note 1	$	$ 300,000
Capital expenditures included in accounts payable and accrued liabilities	$ 7,366,906	$ 1,879,748
Asset retirement obligation additions associated with oil and gas properties	$ 140,985	$
Placement agent warrants recorded as debt issuing costs	$ 1,022,220	$
Sale of Frenchman Creek undeveloped leasehold interest	$ 110,900	$
Reclassification of derivative liabilities to stockholder s equity	$ 3,124,410	$

See notes to unaudited consolidated financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements
(Unaudited)

Note 1 Organization and Summary of Significant Accounting Policies

Organization

Teton Energy Corporation (Teton or the Company) was formed in November 1996 and is incorporated in the State of Delaware. Teton is an independent energy company engaged primarily in the development, production, and marketing of natural gas and oil in North America. The Company s strategy is to increase shareholder value by profitably growing reserves and production, primarily through acquiring under-valued properties with reasonable risk-reward potential and by participating in or actively conducting drilling operations. The Company seeks high-quality exploration and development projects with potential for providing long-term drilling inventories that generate high returns. The Company s current operations are focused in four basins in the Rocky Mountain region of the United States.

Interim Reporting

The accompanying unaudited consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information. Pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC), they do not necessarily include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete financial statements. In the opinion of management, the accompanying unaudited consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company s financial position as of June 30, 2007, the results of operations for the three and six months ended June 30, 2007 and 2006, and cash flows for the six months ended June 30, 2007 and 2006. For a more complete understanding of the Company s operations, financial position and accounting policies, these consolidated unaudited financial statements and the notes thereto should be read in conjunction with the Company s Annual Report on Form 10-K for the year ended December 31, 2006, previously filed with the SEC on March 19, 2007.

In the course of preparing the consolidated financial statements, the Company s management makes various assumptions, judgments, and estimates to determine the reported amount of assets, liabilities, revenue and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts initially established.

The more significant areas requiring the use of assumptions, judgments, and estimates relate to volumes of natural gas and oil reserves used in calculating depletion, the amount of expected future cash flows used in determining possible impairments of oil and gas proved and unproved properties, the amount of accrued capital expenditures used in such calculations, future abandonment obligations, non-cash, stock-based compensation expense related to the Company s Long Term Incentive Plan, and the fair value of derivative liabilities.

Principles of Consolidation

The consolidated financial statements include the accounts of all of the Company s wholly owned subsidiaries. All inter-company profits, transactions, and balances have been eliminated.

Inventory Tubular

Tubular inventory consists primarily of tubular pipe and casing used in the Company s operations and is stated at the lower of average cost or market value.

Sale of Oil and Gas Properties

Effective December 31, 2005, the Company entered into an Acreage Earning Agreement (the Earning Agreement) with Noble Energy, Inc. (Noble), which closed on January 27, 2006. Under the terms of the Earning Agreement, Noble was entitled to earn a 75% working interest in Teton s Denver-Julesburg (DJ) Basin acreage, which included acreage within a defined Area of Mutual Interest (DJ-AMI) after payment of the $3,000,000 and after drilling 20 wells by March 1, 2007 at no cost to Teton. Noble paid the Company $3,000,000 under the Earning Agreement and the Company recorded the entire $3,000,000 (including $300,000, which was reflected as a deposit at December 31, 2005) as a reduction of the investment in its DJ Basin property. Teton is entitled to receive 25% of any net revenues derived from the drilling and completion of those first 20 wells. After completion of the first 20 wells, the Earning Agreement provides that

TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements Continued
(Unaudited)

Teton and Noble will split all costs associated with future drilling and related facilities according to each party s working interest percentage.

On December 21, 2006, the Company received notification from Noble that the first 20 wells had been drilled and completed for the DJ Basin Niobrara pilot project. Therefore, pursuant to the Earning Agreement, Noble earned 75% of all acreage within the DJ-AMI. Teton s interests in the oil and gas rights and leases are recorded directly to Teton DJ Basin LLC, a wholly owned subsidiary.

On May 1, 2007 the Company sold 50% of it s working interest in its Frenchman Creek undeveloped leasehold interest in the DJ Basin to an undisclosed third party, for approximately $110,900. The Company recorded this transaction as a reduction of its investment in the undeveloped leasehold interest.

Purchase of Oil and Gas Properties

On May 5, 2006, the Company closed a definitive agreement with American Oil and Gas, Inc. (American) acquiring a 25% working interest in approximately 87,192 gross acres, or 16,024 net acres in the Williston Basin located in North Dakota for a total purchase price of approximately $6.17 million.

Per the terms of the agreement, the Company paid American approximately $2.47 million in cash at closing and an additional $3.7 million in respect of American s 50% share for drilling and completion of the two planned wells through June 1, 2007. Any portion of the $3.7 million not expended for drilling and completion by June 1, 2007, was required to be paid to American on that date. In addition to the obligation to fund American s share, the Company is also obligated to pay costs in respect of its 25% share of drilling and completion costs of such wells. As of June 30, 2007, the Company satisfied its entire obligation to American.

In May 2007, the Company acquired approximately 12,000 gross and net acres in the Big Horn Basin in the state of Wyoming with a 100 percent working interest for approximately $900,000. At this time, the Company has no partners in this acreage and intends to serve as the project operator.

Debt Issuance Costs

Debt issuance costs are amortized to interest expense over the life of the related credit facility using the effective interest method. The costs incurred in respect to the BNP Paribas Senior Credit Facility in place as of June 30, 2007 had a term of 48 months maturing June 15, 2010 and is included in long-term assets on the Company s consolidated balance sheet. On August 9, 2007, JPMorgan Chase Bank, N.A. (JPMorgan Chase) purchased and assumed the BNP Paribas position in the Credit Facility and the Company and JPMorgan Chase entered into an amended and restated Credit Facility. See Note 9 Subsequent Events and Note 4 Long Term Debt for more information.

In addition, debt issuance costs in respect to the Company s 8% Senior Subordinated Convertible Notes are included in current assets on its consolidated balance sheets. See Note 9 Subsequent Events, JPMorgan Chase Amended and Restated Credit Facility, and Note 3 8% Senior Subordinated Convertible Notes.

Revenue Recognition

Oil and natural gas revenue is recognized monthly based on production and delivery. The Company follows the sales method of accounting for natural gas and crude oil revenue, and recognizes sales revenue on all natural gas or crude oil sold to purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas that are paid in-kind are deducted from revenue.

The volume of natural gas sold may differ from the volume to which the Company is entitled based on the Company s working interest. When this occurs, a gas imbalance is deemed to exist. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under-produced owner(s) to recoup its entitled share through future production. Natural gas imbalances can arise on properties for which two or more owners have the right to take production in-kind. In a typical gas balancing arrangement, each owner is entitled to an agreed-upon percentage of a property s total production; however, at any given time, the amount of natural gas sold by each owner may differ from its allowable percentage. Two principal accounting practices have evolved to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner s entitled share of the current period s production (entitlement method). The Company has elected to use the sales method. If the Company used the entitlement method, the Company s future reported revenue may be materially different than those reported under the sales method.

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Notes to Consolidated Financial Statements Continued
(Unaudited)

At June 30, 2007, there were no gas imbalances in respect to the Company s oil and gas operations.

Successful Efforts Method of Accounting

The Company accounts for its crude oil exploration and natural gas development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes, productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved or an unproved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties or unproved properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature. In this case an allocation of costs to the exploratory and development segments is required. Delineation seismic costs incurred to select development locations within an oil and gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on our operational results reported when we are entering a new exploratory area in an effort to find an oil and gas field that will be the focus of future development drilling activity.

The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial, which will result in additional exploration expense when incurred. In addition, in the event that wells do not produce economic quantities of oil and or gas an impairment event may occur and part or all of the costs capitalized at that point in time would be expensed.

TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements Continued
(Unaudited)

Derivative Financial Instruments

Derivative financial instruments, as defined in Financial Accounting Standard No. 133, Accounting for Derivative Financial Instruments and Hedging Activities (SFAS 133), consist of financial instruments or other contracts that contain a notional amount and one or more underlying variables (e.g., interest rate, security price or other variable), require no initial net investment and permit net settlement. Derivative financial instruments may be free-standing or embedded in other financial instruments. Further, derivative financial instruments are initially, and subsequently, measured at fair value and recorded as liabilities or assets.

The Company generally uses derivative financial instruments to hedge exposures to cash-flow risks. All derivatives are recognized on the balance sheet and measured at fair value. The Company reviews estimated fair values of the derivative contracts as reported by the counterparty s to the contract, and also independently assesses the fair value of derivative contracts and records the changes in the fair value at each reporting period. For derivative contracts that do not qualify as cash flow hedges, changes in the derivative contracts fair value are recorded as unrealized gains and losses based on the change in the contracts fair value and charged to the consolidated statements of income. The Company does not have any derivative contracts that qualify as cash flow hedges. The Company recognizes realized gains and losses in its consolidated statements of income. For the three month and six month periods ended June 30, 2007, the Company recorded unrealized losses on derivative contracts of $104,761 and $197,647, respectively. For the same periods, the Company recorded realized gains on derivative contracts of $201,000 and $255,900, respectively.

The Company has also entered into various types of financing arrangements to fund its business capital requirements, including convertible debt and other financial instruments indexed to the Company s common stock. These contracts require careful evaluation to determine whether derivative features embedded in host contracts require bifurcation and fair value measurement or, in the case of freestanding derivatives (principally warrants) whether certain conditions for equity classification have been achieved. In instances where derivative financial instruments require liability classification, the Company is required to initially and subsequently measure such instruments at fair value. Accordingly, the Company adjusts the fair value of these derivative components at each reporting period through a charge to earnings until such time as the instruments are permitted classification in stockholders equity.

The Company estimates fair values of derivative financial instruments using various techniques (and combinations thereof) that are considered to be consistent with the objective measuring fair values. In selecting the appropriate technique, management considers, among other factors, the nature of the instrument, the market risks that it embodies and the expected means of settlement. For less complex derivative instruments, such as free-standing warrants, the Company generally uses the Black-Scholes-Merton option valuation technique because it embodies all of the requisite assumptions (including trading volatility, estimated terms and risk free rates) necessary to estimate the fair value of these instruments. For complex derivative instruments, such as embedded conversion options, the Company generally uses the Flexible Monte Carlo valuation technique because it embodies all of the requisite assumptions (including credit risk, interest-rate risk and exercise/conversion behaviors) that are necessary to estimate the fair value of these more complex instruments. For forward contracts that contingently require net-cash settlement as the principal means of settlement, the Company projects and discounts future cash flows applying probability-weightage to multiple possible outcomes. Estimating fair values of derivative financial instruments requires the development of significant and subjective estimates that may, and are likely to, change over the duration of the instrument with related changes in internal and external market factors. In addition, option-based techniques are highly volatile and sensitive to changes in the trading market price of our common stock, which has a high-historical volatility. Since derivative financial instruments are initially and subsequently carried at fair values, our income (loss) will reflect the volatility in these estimate and assumption changes.

As of June 30, 2007, derivative financial instruments classified as a component of current liabilities consist of the fair value of financing 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 freestanding derivative financial instruments arose in connection with the 8.0% Senior Subordinated Convertible Notes financing that is more fully discussed in Note 3.

During the three and six months ended June 30, 2007, the Company incurred expense from the valuation adjustments to derivative liabilities as follows:

Changes in fair value

Derivative Financial Instruments:	
Financing warrants	$ 1,461,024
Compound embedded derivative	306,621
Other warrants	561,111
	2,328,756
Day-one loss from derivative allocation	2,300,634
Loss or derivative liabilities	$ 4,629,390

Our derivative liabilities as of June 30, 2007, and our derivative expense arising from fair value adjustments during the three and six months ended June 30, 2007 are significant to our consolidated financial statements. The magnitude of the derivative expense reflects the following:

(a) During the short period (May 18, 2007 to June 30, 2007) that our derivative liabilities were classified as liabilities, the trading price of our common stock, which significantly affects the fair value of our derivative financial instruments, experienced a material price increase from $4.66 to $5.20.

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Notes to Consolidated Financial Statements Continued
(Unaudited)

(b) During May 2007, we entered into a $9,000,000 convertible debt and warrant financing arrangement, more fully discussed in Note 3. In connection with our accounting for this financing arrangement we encountered the unusual circumstance of a day-one derivative loss related to the recognition of derivative instruments arising from the arrangement. That means that the fair value of the bifurcated compound derivative and warrants exceeded the net proceeds that we received from the arrangement and we were required to record a loss to record the derivative financial instruments at fair value. The loss that we recorded amounted to $2,300,634. We did not enter into any other financing arrangements during the periods reported that reflected day-one losses.

Significant valuation assumptions:

The following table sets forth the significant assumptions, or ranges of assumptions, underlying the valuation of derivative financial instruments:

Freestanding Warrants:

	Inception Date **(a)**	Reclassification Date **(a)**	Quarter End
Trading market value	$4.66 $4.67	$5.11	$ 5.20
Strike prices	$1.75 $5.00	$1.75 $4.35	$ 5.00
Estimated term (years)	0.88 6.78	0.77 6.66	4.88
Estimated volatility	43.46% 85.04%	39.01% 80.07%	69.18%
Risk-free rates	4.62% 4.82%	4.95% 5.02%	4.92%

(a) See Note 3 for pertinent information regarding the origination of freestanding warrants that were classified or reclassified as derivative liabilities. The inception and reclassification date assumptions include those applied to freestanding warrants that were reclassified from stockholders equity. See Note 5 Stockholders Equity.

Compound Derivative:

	Inception Date **(b)(c)**	Reclassification Date **(b)(c)**	Quarter End
Trading market value	$4.66	$5.11	
Conversion price	$5.00	$5.00	
Equivalent term (years)	1.00	.885	
Equivalent volatility	43.67% 45.50%	43.29% 50.63%	
Equivalent risk-adjusted interest rate	8.42% 9.00%	8.42% 9.00%	
Equivalent credit-risk adjusted yield	13.67% 22.67%	13.67% 22.67%	

(b) See Note 3 for pertinent information regarding the origination of compound-embedded derivative financial instruments. On June 28, 2007, the compound-embedded derivative financial instruments were reclassified to stockholders equity in accordance with EITF 06-07 Issuer s Accounting for a Previously Bifurcated Conversion Option in a Convertible Debt Instrument When the Conversion Option No Longer Meets the Bifurcation Criteria in FAS No. 133.

(c) Equivalent assumption amounts and percentages reflect the net results of multiple simulations that the Monte Carlo Simulation methodology applies to multiple data points in the ranges of the underlying assumptions.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements Continued
(Unaudited)

Reclassification

Certain amounts in the 2006 financial statements have been reclassified to conform to the 2007 presentation.

Income Taxes

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes , an interpretation of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (FIN 48). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

The Company adopted the provisions of FIN 48 effective January 1, 2007. The adoption of this accounting principle did not have an effect on our financial statements as of June 30, 2007.

Recently Issued Accounting Pronouncements

In September 2006, the FASB issued Statement No. 157, Fair Value Measurements (SFAS 157). The adoption of SFAS 157 is not expected to have a material impact on our consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop certain fair value measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The Company is currently evaluating this pronouncement for any impact that it might have on its financial statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. 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. This statement is effective beginning January 1, 2008, and the Company is currently evaluating this pronouncement for any impact that it might have on its financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements Continued
(Unaudited)

Note 2 Earnings per Share

Basic earnings per common share (EPS) are computed by dividing income available to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution that would occur if securities or other contracts to issue common stock were exercised or converted into common stock. All potential dilutive securities have an anti-dilutive effect on earnings (loss) per share and accordingly, basic and dilutive weighted average shares are the same. As of June 30, 2007, a total of 8,499,218 shares of dilutable securities have been excluded from the calculation of EPS as the effect of including these securities would be anti-dilutive.

Note 3 8% Senior Subordinated Convertible Notes

On May 16, 2007, the Company closed on a financing consisting of $9.0 million face value of 8% senior subordinated convertible notes (the Notes) due May 16, 2008 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. In addition, the warrant agreement allows for the exercise of the warrants on a cashless basis. Net proceeds from the sale of the Notes and warrants amounted to $8.3 million after fees and expenses. In addition, the Company issued to the Placement Agent warrants to purchase 360,000 shares of the Company s common stock at a $5.00 strike price for five years. The fair value of the Placement Agent warrant was $1,022,220 using the Black-Scholes-Merton valuation technique and has been initially recorded as debt issuance costs. The Notes bear interest at 8% per annum which is payable on a quarterly basis on July 1, October 1, January 1 and April 1, beginning July 1, 2007, either in cash or common stock at the Company s option. The Notes were initially convertible into common stock at a conversion price of $5.00 per share subject to adjustment at maturity to a then market-indexed rate. The conversion feature also provided full-ratchet anti-dilution protection in the event of sales of shares or other share-indexed instruments below the conversion price. The Notes are unsecured but provide for penalties in the event of default.

The Company evaluated the terms and conditions embedded in the Notes for indications of features that were not clearly and closely related to debt-associated risk and concluded that the conversion feature, share-indexed interest feature, anti-dilution protections and certain default features required compounding and bifurcation as a derivative liability in accordance with FAS 133. In addition, the financing and Placement Agent warrants did not meet all the conditions for equity classification on the inception date of the transaction and required liability classification. Since derivative financial instruments are initially and subsequently measured at fair value, the Company allocated financing proceeds to those instruments plus other financing components, as follows.

Derivative Financial Instruments:	
Financing warrants	$ 11,194,020
Compound embedded derivative	1,128,834
Day-one loss from derivative allocation	(2,300,634)
Direct finance costs	(1,732,611)
	$ 8,289,609

On June 28, 2007, the Company amended the Notes with the holders to, among other things, changing the conversion at maturity from a variable conversion price to a fixed $5.00 conversion price as the floor at maturity and modifying the anti-dilution protections to fix the $5.00 price as the floor. While the amendment did not give rise to an extinguishment of the original Notes, the Company concluded that the Notes met the Conventional Convertible Exemption to further classification of the compound embedded derivative in stockholders equity. In addition, the removal of the variable conversion rate resulted in reclassification of the Placement Agent and certain other warrants to stockholders equity; the financing warrants continue to require classification as derivative liabilities. Accounting for the reclassifications in accordance with EITF 06-7 provided that the Company adjust the instruments to fair value on the amendment dates and reclassify the balances to stockholders equity without any adjustment to the carrying value or amortization of the host debt instrument. Details for reclassifications are provided in Note 5.

As of June 30, 2007, the Company has recorded $163,001 of amortization of the Note discount applying the effective method.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements Continued
(Unaudited)

Note 4 Long-Term Debt

Long term debt consisted of the following at June 30, 2007 and December 31, 2006:

	June 30, 2007	December 31, 2006
Senior Bank Credit Facility	$ 6,000,000	$

On June 15, 2006, we entered into a $50 million senior revolving credit facility (the Credit Facility) with BNP Paribas as administrative agent, sole lead arranger, and sole book runner. The original maturity date of the Credit Facility was June 15, 2010.

The Credit Facility provided for as much as $50.0 million in borrowing capacity, depending upon a number of factors, such as the projected value of our proven oil and gas assets. The borrowing base for the Credit Facility at any time will be the loan value assigned to the proved reserves attributable to our subsidiaries direct or indirect oil and gas interests. The Credit Facility had an initial borrowing base on June 15, 2006 of $3.0 million. The borrowing base was increased to $6.0 million on March 12, 2007, and increased to $10.0 million on July 19, 2007.

Under the Credit Facility, each loan bears interest at a Eurodollar rate or a base rate, as requested by the Company, plus an additional margin based on the amount of the Company s total outstanding borrowings relative to the total borrowing base. The Eurodollar rate is based on the London Interbank Offered Rate. The base rate is the higher of the Prime Rate or the Federal Funds Rate plus one-half of one percent. In addition, under the terms of the Credit Facility, Teton is required to pay a commitment fee based on the average daily amount of the unused amount of the commitment of each lender. This fee accrues at a rate of 0.50% per annum and is paid quarterly in arrears on the last day of March, June, September, and December of each year and on the date on which the Credit Facility is terminated. Loans made under the Credit Facility are secured by a first mortgage against the Company s properties, a pledge of the equity of all subsidiaries and a guaranty by those same subsidiaries.

Costs were incurred in connection with the Credit Facility and are considered part of debt issuance costs and are included in the Company s non-current assets. The remaining unamortized debt issuance costs at June 30, 2007 were $209,335. Those debt issuance costs are amortized to interest expense over the life of the Credit Facility using the effective interest method. As the Credit Facility has been amended as follows, the Company will charge the entire unamortized balance of $209,335 to expense during the third quarter of 2007.

The Credit Facility contains customary affirmative and negative covenants such as minimum/maximum ratios for liquidity and leverage. Under the terms of the Credit Facility, certain covenants are not immediately effective and are phased in beginning at the end of the first quarter of 2007 and are then gradually phased-in over the first three quarters of 2007. The Company amended the Credit Facility on May 14, 2007. The Amendment provided for the total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization and Exploration) ratio to be effective September 30, 2007. At June 30, 2007, the Company was not in compliance with certain covenants. Those covenants are either no longer required or in compliance as a result of the amended and restated Credit Facility with JP Morgan Chase as of August 9, 2007. See Note 9 Subsequent Events for Additional Information.

The outstanding balance on the Credit Facility as of June 30, 2007 is $6.0 million. As of August 8, 2007 the outstanding balance on the Credit Facility was $10 million.

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Note 5 Stockholders Equity

The Company s authorized capital stock consists of 250,000,000 shares of common stock, $.001 par value per share (the Common Stock) and 25,000,000 shares of preferred stock, $.001 par value per share (the Preferred Stock).

During the six months ended June 30, 2007, holders of options of the Company s Common Stock exercised 565,478 options, and purchased an equivalent number of shares of the Company s Common Stock. The Company collected proceeds of $2,018,755 during the first six months of 2007 in respect to the exercise of these stock options. See Note 6 Stock-based Compensation for additional information on stock options.

During the six months ended June 30, 2007, the Company issued 426,518 restricted shares of Common Stock which were awarded to directors, officers employees and consultants under the 2005 LTIP plan for 2006 year milestone achievements. The Company issued 70,001 restricted shares of Common Stock that vested during the year ended December 31, 2006 and 11,667 restricted shares of Common Stock that vested during the six month period ended June 30, 2007. See Note 6 Stock-Based Compensation for additional information on restricted Common Stock.

In connection with the resignation of the Company s former contract Chief Financial Officer, effective March 31, 2006, 50,000 restricted shares of Common Stock were returned to the Company as an agreed-upon reduction in service fees charged. The return of such shares had been recorded as a reduction in accounting fees totaling $157,500 at March 31, 2006.

In respect to warrants, the following table presents the activity for warrants outstanding for the six months ended June 30, 2007:

	Shares	**Price**
Outstanding December 31, 2006	867,819	$ 3.14
Granted	3,960,000	5.00
Exercised		
Forfeited/canceled		
Outstanding June 30, 2007	4,827,819	$ 4.67

The following table presents the composition of warrants outstanding and exercisable as of June 30, 2007:

Range of Exercise Prices	**Number**	**Price***	**Life***
$1.75 - $3.24	861,819	$ 3.13	4.1
$3.48 - $4.35	6,000	3.81	1.1
$5.00	3,960,000	5.00	4.9
Total shares outstanding and exercisable	4,827,819	$ 4.67	4.8

* Price and Life reflect the weighted average exercise price and weighted average remaining contractual life

(in years),
respectively.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements Continued
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Derivative Reclassifications:

Current accounting standards provide that the Company is required to evaluate existing derivative financial instruments for classification in stockholders equity or as derivative liabilities at the end of each reporting period, or upon the occurrence of any event that may give rise to a presumption that the Company could not share or net-share settle the derivatives. As discussed in Note 3, on May 16, 2007, the Company entered into a convertible note and warrant financing that initially provided for a conversion rate that was indexed to a forward trading market price. In this instance, it was concluded that the feature placed share settlement outside of the Company s control due to (without regard to probability) the potential of the trading market price declining to a level where the Company would have insufficient authorized shares with which to settle all of its share-indexed instruments. Accordingly, certain non-exempt warrants (tainted warrants) required reclassification on the date of the financing. As further discussed in Note 3, the Company amended the debt agreement such that liability classification for certain derivatives, including the tainted warrants, was no longer required. On that date certain of the derivatives were reclassified to stockholders equity.

The following table illustrates the reclassifications of derivatives at fair values as of June 30, 2007:

Reclassifications:	
Existing warrants tainted to derivative liabilities	$ 4,951,485
Compound embedded derivative no longer requiring bifurcation	(1,435,455)
Financing warrants no longer tainted - placement agents	(1,127,844)
Existing warrants no longer tainted to stockholders equity	(5,512,596)
Net change in stockholders equity	$ (3,124,410)

Note 6 Stock-based Compensation

At the Company s 2005 Annual Meeting, the stockholders approved a Long Term Incentive Plan (the LTIP). The LTIP is a performance-based compensation plan whereby up to 10% of the outstanding shares at the beginning of each plan year, except for the first year wherein 20% of the outstanding shares are available (not to exceed, in any three year period, 35% of the outstanding shares of the Company) can be awarded to certain employees, directors and consultants. In most cases, awards will be linked to the performance of the Company as measured by performance metrics that, at the time of the grants, are deemed necessary by the Compensation Committee of the Board of Directors for the creation of shareholder value.

On July 26, 2005, the Compensation Committee finalized the award of 800,000 performance share units to certain Company employees and directors which vest during each of 2005, 2006 and 2007 provided the Company meets certain performance targets as established by the Committee. The vesting of the performance share units into common stock is conditioned on the participants remaining employed by the Company at each measurement date and will vest over one, two and three year periods. The performance share units will vest into common stock on a sliding scale from 50% to 200%, depending on the performance levels achieved by the Company. No LTIP shares were earned for the 2005 year as the objectives established by the Compensation Committee were not met.

During 2006, the Compensation Committee awarded 1,945,000 performance share units under the LTIP to executives, directors, certain employees and consultants which vest during each of 2006, 2007 and 2008 provided the Company meets certain performance targets that are established by the Committee. The vesting of the performance share units into Common Stock is conditioned on the participants remaining employed by the Company at each measurement date and will vest over one, two and three year periods. The performance share units will vest into Common Stock on a sliding scale from 50% to 200%, depending on the performance levels achieved by the Company.

A summary of the stock-based compensation expense recognized in the results of operations is set forth below:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	2006	2007	2006
LTIP performance share units directors, employees and consultants	$ 741,359	$ 557,637	$ 1,482,358	$ 938,273
Restricted common stock directors, employees and consultants	152,806	139,538	301,279	80,514
Stock options	4,383	9,815	8,766	19,726
Total	$ 898,548	$ 706,990	$ 1,792,403	$ 1,038,513

TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements Continued
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Each of the component categories of stock-based compensation is described more fully below.

Long Term Incentive Plan

On June 28, 2005, the Company s shareholders approved the LTIP that permits the grant of stock options, stock appreciation rights, performance share units, and restricted share units to employees, directors, consultants and vendors as directed by the Compensation Committee of the Board of Directors, with management recommendations regarding consultants, vendors, and non-executive employees.

The Compensation Committee establishes a pool (Pool) of Performance Share Units (Units) under the LTIP each year (each year becoming a Grant Year), subject to limits set forth in the LTIP, and allocates the pool to officers, directors, employees and consultants, and grants units (Grants) to individual participants. The Grants vest over a period of time, typically over a three-year period. In addition to vesting based on a participant s continued employment with or service to the Company over the period of a Grant, the Units must be earned based on achieving performance goals set forth by the Compensation Committee. The Compensation Committee designates performance levels as Threshold, Base, and Stretch. If the Company achieves 100% of the Base level of performance, 100% of the Units vesting in that year will be earned. If the Company achieves the Threshold level of performance, 50% of the Units will be earned. If the Company achieves the Stretch level of performance, 200% of the Units will be earned. If the Threshold performance is not achieved, no Units are earned. Units may not be earned above the 200% Stretch level. Once the Units are vested and earned, they are released to the participants as Common Stock.

The value of each Unit is measured and determined based on the value of the Company s Common Stock at the date the Unit is granted. Annual compensation expense is calculated based upon the number of Units vested and earned each year. Each quarter the Company estimates the level of performance expected to be achieved by year-end and records an estimated expense accordingly.

During the third quarter of 2005 (the 2005 Grant Year) the Compensation Committee established a Pool of 400,000 Base Units and 800,000 Stretch Units (the 2005 Grants). During 2005, grants of 372,500 Base Units and 745,000 Stretch Units were granted by the Compensation Committee. During 2006 additional grants of 75,000 Base Units and 150,000 Stretch Units were granted by the Compensation Committee. The Units vest in three tranches (20% in 2005, 30% in 2006 and 50% in 2007), provided the goals set forth by the Compensation Committee are met. The performance goals are based upon attaining specific objectives, including: (a) achieving certain levels of oil and gas reserves in each year of the grant, (b) achieving a certain level of oil and gas production in each year of the grant, (c) achieving a certain level of stock price performance in each year of the Grant, (d) maintaining finding and development costs within certain ranges during each year of the Grant and (e) management s efficiency and effectiveness in its operations. On March 13, 2007, based on the achievement of a 126.54% composite index in respect of the milestones established for 2006 under the 2005 Grants, 134,768 shares were earned and awarded, to directors, employees and consultants.

In December 2005, the Compensation Committee reserved for 2006 (the 2006 Grant Year) 1,000,000 Base Units and 2,000,000 Stretch Units (the 2006 Grants). In March 2006, the Compensation Committee increased the Pool of Base Units being reserved to 1,250,000 and Stretch Units to 2,500,000 to accommodate anticipated executive hires. During 2006, a total of 984,625 Base Units and 1,969,250 Stretch Units were granted by the Compensation Committee. The remainder of Units in the 2006 Pool reverted to shares deemed available for future issuance, in accordance with the terms of the LTIP.

The 2006 Grants vest in three tranches (20% in 2006, 30% in 2007 and 50% in 2008), provided the goals set forth by the Compensation Committee are met. The performance objectives established by the Compensation Committee for the 2006 Grants are based on the (a) value of completed acquisitions in each year of the Grant relative to the Company s market capitalization at the end of the previous calendar year, (b) stock price performance relative to an index of comparable companies over the period of the Grant established by an independent third party, and (c) management s efficiency and effectiveness in its operations. These objectives represent 100% of the goals for senior executives of the Company and varying but lesser percentages for other employees, whose vesting includes a combination of individual, team, and corporate objectives in each year of the 2006 Grant. On March 13, 2007, based on the achievement of a 150% composite index for the 2006 Grants under the 2006 Grant Year, 291,750 shares were earned and awarded to directors, employees and consultants.

TETON ENERGY CORPORATION AND SUBSIDIARIES
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A summary of the Performance Base Units for the six months ended June 30, 2007 reflects the total share units granted less vested and released share units less forfeited/cancelled share units are set forth below:

	2005 Grant Year		2006 Grant Year		Total	
	Base Performance Share Units	Weighted Average Grant Date Fair Value	Base Performance Share Units	Weighted Average Grant Date Fair Value	Base Performance Share Units	Weighted Average Grant Date Fair Value
Total pool	400,000		1,250,000		1,650,000	
Grants outstanding at beginning of year	177,500	$ 4.95	778,000	$ 6.71	955,500	$ 6.38
Grants during the period		$		$		$
Vested and released		$		$		$
Forfeited/cancelled		$		$		$
Outstanding at end of period	177,500	$ 4.95	778,000	$ 6.71	955,500	$ 6.38

Restricted Common Stock

In December 2005, grants of 195,000 restricted shares of Common Stock were made pursuant to the Company s LTIP, which vest equally over 3 years, beginning January 1, 2006, based solely on service and continued employment throughout the vesting period. Of the 195,000 restricted shares, 65,001 shares vested in 2006. An additional 69,000 share grants were made during the 2006 year of which 64,000 vest over three years and 5,000 vested immediately. In the six months ended June 30, 2007, 55,000 share grants were made which vest over three years. Compensation expense was recorded for the six months ended June 30, 2007 and 2006 based on the market value of the Common Stock on the date of the grant, recorded over the related service period.

A summary of the status of restricted stock activity granted under the Company s LTIP for the six month period ended June 30, 2007, is set forth below:

	Restricted Stock	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2006	193,999	$ 5.97
Granted	55,000	$ 5.11
Vested	(11,667)	$ 6.69
Forfeited		$
Non-vested at June 30, 2007	237,332	$ 5.74

Stock Options

The Company granted 45,000 stock options effective during 2006 under the 2003 Employee Stock Option Plan. These options are exercisable at $3.11 per share and vest over a three-year period, assuming the employees remain in our employ. As of June 30, 2007, the Company estimated the unrecognized value of the stock options at $17,533 using the Black-Scholes option-pricing model with the following assumptions: volatility of 109.46%, a risk-free rate of approximately 4%, zero dividend payments and a life of 10 years. As of June 30, 2007, there were 6,800 unvested stock options outstanding, and the total unrecognized compensation cost adjusted for estimated forfeitures related to non-vested options was $17,533, which is expected to be recognized over the remaining service period of 12 months.

TETON ENERGY CORPORATION AND SUBSIDIARIES
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A summary of stock option activity for the six months ended June 30, 2007 is set forth below:

	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at December 31, 2006	2,088,545	$ 3.56		
Granted		$		
Exercised	(565,478)	$ 3.57		
Forfeited/expired		$		
Outstanding at June 30, 2007	1,523,067	$ 3.52	5.86	$ 2,511,987
Exercisable at June 30, 2007	1,516,267	$ 3.54	5.89	$ 2,497,775

Note 7 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, removal of equipment and facilities from leased acreage, and any required land reclamation in accordance with applicable state and federal laws. Teton determines asset retirement obligations by calculating the present value of estimated cash flows related to future retirement obligations.

The following table provides a reconciliation of the Company s asset retirement obligations for the three and six months ended June 30, 2007 and June 30, 2006.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	2006	2007	2006
Beginning asset retirement obligation	$ 197,613	$ 3,895	$ 78,115	$ 3,851
Additional liabilities incurred	29,094	20,447	51,860	20,491
Revisions in estimated cash flows			89,125	
Accretion expense	12,769		20,376	
Ending asset retirement obligation	$ 239,476	$ 24,342	$ 239,476	$ 24,342

Note 8 Commitments

On February 1, 2007, the Company executed an employment agreement with Dominic J. Bazile II to become Executive Vice President and Chief Operating Officer. The employment agreement provides for an initial salary for Mr. Bazile of $225,000 per year. Under the terms of the employment agreement, Mr. Bazile is entitled to 12 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Bazile s employ for a two-year period if the agreement is not terminated by notice to either party during 60 days prior to the end of the initial stated term, which is two years. In addition, Mr. Bazile s employment agreement has an indemnification agreement.

The Company entered into a three-year lease for office space, which expires in April 30, 2009. Contractual commitments under this lease are approximately $61,000 for the remainder of 2007, $129,000 for 2008, and $44,000 for 2009.

During 2006, the Company established a SIMPLE IRA plan, allowing for the deferral of employee income. The plan provides for the Company to match employee contributions up to 3% of gross cash compensation. For the six months ended June 30, 2007, the Company contributed $29,632 to this plan.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
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Note 9 Subsequent Events

JPMorgan Chase Amended and Restated Credit Facility

On August 9, 2007, the Company entered into an amended and restated $50 million revolving credit facility (the Credit Facility) with JPMorgan Chase Bank, N.A. (JPMorgan Chase), as administrative agent. JPMorgan Chase assumed the Company s previous credit facility with BNP Paribas. The Credit Facility matures on August 9, 2011, and is available to be used for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit.

The Credit Facility provides for as much as $50 million in borrowing capacity, depending upon a number of factors, such as the projected value of the Company s proven oil and gas assets. The borrowing base for the Credit Facility at any time will be the loan value assigned to the proved reserves attributable to the Company s subsidiaries direct or indirect oil and gas interests. The Credit Facility has an initial borrowing base of $14 million with an initial conforming borrowing base of $11 million. The borrowing base (and, until November 1, 2008, the conforming borrowing base) is scheduled to be redetermined on a semi-annual basis, based upon an engineering report delivered by the Company from an approved petroleum engineer. The first redetermination of the borrowing base is scheduled for November 1, 2007. The Company may request, and JPMorgan Chase may permit, additional rederminations of the borrowing base and/or conforming borrowing base between scheduled redeterminations. Any interim redetermination of the conforming borrowing base (prior to November 1, 2008) will be made based upon JPMorgan Chase s application of certain credit criteria. On November 1, 2008, the borrowing base will be automatically reduced to the amount of the conforming borrowing base, and at all times thereafter will be equal in amount to the conforming borrowing base.

Under the Credit Facility, each loan bears interest at a Eurodollar rate or a base rate, as requested by the Company, plus an additional margin based on the amount of our total outstanding borrowings relative to the total borrowing base. The Eurodollar rate is based on the London Interbank Offered Rate. The base rate is the higher of the Prime Rate or the Federal Funds Rate plus one-half of one percent. In addition, under the terms of the Credit Facility, the Company is required to pay a commitment fee based on the average daily amount of the unused amount of the commitment of each lender. This fee accrues at a rate of 0.375% or 0.500% per annum, depending on the percentage of our borrowing utilization, and is paid quarterly in arrears on the last day of March, June, September, and December of each year and on the date on which the Credit Facility is terminated. Loans made under the Credit Facility are secured primarily by a first mortgage against the Company s oil and gas assets and by a pledge of the equity of the Company s subsidiaries and a guaranty by those same subsidiaries. The Credit Facility contains customary affirmative and negative covenants such as minimum/maximum ratios for liquidity and leverage. Under the terms of the Credit Facility, certain covenants are not immediately effective, and commence at the end of our third or fourth quarters of fiscal 2007. The Company s initial advance from the Credit Facility was $11 million. Approximately $10.2 million of the $11 million gross proceeds received was used to assume BNP Paribas s position and to pay fees. The Company plans to use the remaining net proceeds of approximately $0.8 million for general corporate purposes, working capital, and capital expenditures.

Common Stock Offering

The Company completed a registered direct offering of its Common Stock to a selected group of investors to purchase an aggregate of 964,060 shares of Common Stock, at a price of $5.05 per share, for gross proceeds of approximately $4.9 million, before fees and expenses. The Company received $4.6 million after the payment of fees and expenses. The offering also included 337,421 warrants to purchase 337,421 shares of common stock with an exercise price of $6.06 per share with a five-year term. Ferris, Baker Watts, Incorporated acted as lead placement agent, with Commonwealth Associates, L.P. as co-placement agent for the offering.

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

FORWARD-LOOKING STATEMENTS

With the exception of historical matters, the matters discussed herein are forward-looking statements that involve risks and uncertainties. Forward- looking statements include, but are not limited to, statements concerning the expectation or belief regarding future events, and may include words or phrases such as will likely result, are expected to, will continue, is anticipated, estimate, projected, intends to or similar expressions, which are intended to identify forward looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Our actual results could differ materially from the results discussed in such forward-looking statements. There is absolutely no assurance that we will achieve the results expressed or implied in forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, our ability to successfully implement our strategy to acquire additional oil and gas properties and our ability to successfully manage and operate our newly acquired oil and gas properties or any properties subsequently acquired by us as well as those factors discussed below and in our Annual Report on Form 10-K for the year ended December 31, 2006, under the subsection Forward-Looking Statements in the Management s Discussion and Analysis of Financial Condition and Results of Operations section, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Management s Discussion and Analysis

Overview

Teton Energy Corporation (the Company, Teton, we, or us) was formed in November 1996 and is incorporated in t State of Delaware. We are an independent energy company engaged primarily in the development, production, and marketing of natural gas and oil in North America. Our strategy is to increase shareholder value by profitably growing reserves and production, primarily through acquiring under-valued properties with reasonable risk-reward potential and by participating in or actively conducting drilling operations in order to exploit our properties. We seek high-quality exploration and development projects with potential for providing long-term drilling inventories that generate high returns.

Accomplishments and Highlights, Quarter Ended June 30, 2007

Our current operations are located in the Rocky Mountain region of the United States.

Financial and operational highlights for the three months ended June 30, 2007 include the following:

Our net loss increased to $7,244,967 ($0.45 per share) for the three month period ended June 30, 2007 from $1,526,345 ($0.13 per share) for the same period in 2006. The increase of $5,718,622 is due to increased general and administrative expenses, higher exploration expenses, higher depletion expense, and significant losses on derivative liabilities, partially offset by higher oil and gas sales.

Our oil and gas sales increased to $832,943, which is based on the sale of 266,110 mcf equivalent of natural gas at an average price of $3.13 per mcf equivalent after a total deduction of $157,415 ($0.59 per mcf) for gathering, fuel, transportation and marketing expenses. Included in our oil and gas sales, our net revenue from the sale of oil produced and sold from the Champion 1-25H well in the Williston Basin totaled approximately $35,242 and natural gas sales from the DJ Basin totaled approximately $27,476.

We participated in the drilling of 13 development wells in the current quarter to total depth and connected 9 wells to production in the Piceance Basin of Colorado.

We participated with Noble Energy Inc. (Noble) in the construction of gas gathering and related infrastructure systems and in the drilling of 7 additional wells in our Area of Mutual (AMI) interest in the DJ basin during the quarter. Noble connected a total of 11 wells to sales during the quarter. During the quarter ended June 30, 2007 we determined that the development of the Grant and Hagan areas of the AMI with Noble is expected to be economic, and we are proceeding with this development in these areas.

On May 16, 2007, the Company closed on $9.0 million of proceeds from convertible 8% senior subordinated convertible notes (the Notes) due May 16, 2008. Net proceeds received by the Company from the issuance of these Notes were approximately $8.3 million, after fees and expenses.

For the six months ended June 30, 2007, we invested $14,933,234 in oil and gas capital expenditures as further described below.

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Results of Operations for the Three Months Ended June 30, 2007

We had a net loss for the three months ended June 30, 2007, of $7,244,967, an increase of $5,718,622 over the same period in 2006. The increase was primarily due to an increase in general and administrative expenses, depreciation and depletion expense, exploration expense, and significant losses on derivative liabilities and related accretion expense. The increase in the net loss was partially offset by higher oil and gas sales, as further described.

Our oil and gas sales for the quarter ended June 30, 2007 of $832,943 represented an increase of $182,709, or 28% over the same period in 2006. During the three months ended on June 30, 2007, oil and gas sales net to our interest totaled 266,110 mcf equivalent, at an average price of $3.13 per mcf equivalent after deducting $157,415 ($0.59 per mcf equivalent) for gathering, fuel, transportation and marketing expenses. During the three months ended June 30, 2006, our oil and gas sales totaled 131,343 mcf, resulting in $650,234 in oil and gas sales, at an average price of $4.95 per mcf equivalent after deducting $101,797 ($0.78 per mcf equivalent) for gathering, fuel, transportation and marketing expenses. The higher oil and gas sales are primarily the result of increased number of wells on production in the Piceance Basin (29 wells on production at June 30, 2007 versus 10 wells on production at June 30, 2006). In addition, as of June 30, 2007, we have 18 wells on production in the DJ Basin and 2 wells on production in the Williston Basin, as compared to no wells on production in either of these basins in the same period in 2006.

Lease operating expenses and production taxes ($64,388 and $89,306, respectively) for the three month period ended June 30, 2007, totaled $153,694, or 18% of oil and gas sales, or $0.58 per mcf equivalent. Lease operating expense and production taxes ($114,410 and $11,832, respectively) for the three month period ended June 30, 2006 totaled $126,242, or 19% of oil and gas sales and $0.96 per mcf equivalent. The increase in lease operating expenses and production taxes in 2007 of $27,452, or 22%, is primarily due to the increase in the number of producing wells in 2007 as compared to 2006.

General and administrative expense increased by $474,349 during the quarter ended June 30, 2007 as compared to the same period in 2006, primarily as a result of:

- Non-cash compensation expense for our LTIP and restricted stock plans which increased by $191,378 due an increase in employees associated with the growth in our operations and estimated levels of achievement in respect to our compensation plans.

- Investment banking fees of $170,697 associated with capital raises that were not consummated.

- Higher costs associated with investor relations and corporate communications of $71,226 due to increased activity levels.

- Legal and accounting fees of $138,617 in respect to capital raises that were not consummated.

Certain general and administrative expenses were lower during the six months June 30, 2007 as compared to the same period in 2006:

- Expenses in respect to exploration activities included in general and administrative expenses, that have been allocated to exploration expense, including third party charges and internal professional staff allocations of $127,172.
- Lower stock transfer expenses of $46,726.

Depreciation and depletion expense increased by $251,115 to $581,288 for the three months ended June 30, 2007, as compared to the $330,173 incurred during the same period in 2006, principally due to the higher gas sales volumes in 2007 compared to 2006.

During the three months ended June 30, 2007, we incurred exploration-related expenses of $308,668, an increase of $233,923 as compared to the $74,745 incurred during the same period in 2006. The increase is a result of higher expenses incurred for seismic projects on our DJ Basin properties as well as increased exploration activities associated with our growth in operations.

Our expenses in respect to other income (expense) increased by $4,901,723 as a result of $4,629,390 of losses on derivative liabilities and $194,380 of interest accretion associated with the derivative liabilities included in interest expense. In addition, interest expense, including debt issuance amortization expense increased by $138,806. We did not have any debt outstanding as of June 30, 2006. The increase in expense for the 2007 period also included realized gains of $201,000 in respect to natural gas hedging contracts and unrealized losses of $104,761 in respect to those contracts as well. We did not have any hedging contracts in place as of June 30, 2006.

Our interest expense over the term of our $9 million 8% senior subordinated convertible notes will increase substantially due to the significant original issue discount resulting from the application of FAS 133 and the effect of applying the effective interest method. In addition, our derivative expense is subject to adjustment at each reporting period. The amount of charge (or credit) is largely dependent upon assumptions underlying valuation techniques we apply. However, current derivative balances are highly susceptible to changes in our trading market prices. Increases in our trading market prices could result in additional significant charges.

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Results of Operations for the Six Months Ended June 30, 2007

We had a net loss for the six months ended June 30, 2007, of $9,045,913, an increase of $6,256,942 over the net loss from for the same period in 2006. The increase was due primarily to general and administrative expense, depreciation and depletion expense, exploration expense, and significant losses on derivative liabilities and related accretion expense. The increase in net loss was partially offset by higher oil and gas sales, as further described.

Our oil and gas sales for the six month period ended June 30, 2007 were $1,901,284, an increase of $960,801 or 102% over the same period in 2006. For the six months ended June 30, 2007, our oil and gas production totaled 468,997 mcf equivalent at an average price of $4.05 per mcf equivalent after a total deduction of $286,797 ($0.61 mcf equivalent) for gathering, fuel, transportation and marketing expenses. In the six months ended June 30, 2006, oil and gas production net to our interest totaled 176,533 mcf resulting in $940,483 in oil and gas sales, at an average price of $5.33 per mcf equivalent after a total deduction of $144,578 ($0.82 per mcf equivalent) for gathering, fuel, transportation and marketing expenses. The higher oil and gas sales are due to 29 wells on production in the Piceance Basin, 7 wells on production in the DJ Basin, and 2 wells on production in the Williston Basin as of June 30, 2007 as compared to a total of 10 wells on production, all located in the Piceance Basin, for the same period in 2006.

Lease operating expenses and production taxes ($107,281 and $153,306, respectively) for the six month period ended June 30, 2007, totaled $260,587, or 14% of oil and gas sales, or $0.56 per mcf equivalent. Lease operating expense and production taxes ($148,198 and $19,850, respectively) for the six month period ended June 30, 2006, totaled $168,048, or 18% of oil and gas sales, or $0.95 per mcf equivalent .The increase in lease operating expenses and production taxes in 2007 of $92,539 or 55%, as compared to 2006, is due primarily to the increase in the number of producing wells in 2007 as compared to 2006.

During the six months ended June 30, 2007, our general and administrative expenses increased by $1,010,894, or 33% to $4,059,639 from $3,048,745 incurred in the comparable period in 2006. Significant changes in general and administrative expenses for the six months ended June 30, 2007, compared to the same period in 2006 include:

Non-cash compensation expense for our LTIP and restricted stock plans which increased by $595,491 due an increase in employees associated with the growth in our operations and estimated levels of achievement in respect to our compensation plans.

Legal and accounting fees increased by $248,807, primarily as a result of a one time credit to accounting fees recognized during the first quarter of 2006 of $157,500, related to the return of 50,000 shares of our Common Stock from our former Chief Financial Officer. In addition, after taking into account this one time credit, legal and accounting fees increased by $91,307 in the 2007 period, primarily due to increased capital raise activity levels.

Investment banking fees of $158,197 associated with capital raises that were not consummated

Corporate communications expense increased by $109,361, due to higher investor relations activity levels.

The following general and administrative expenses were lower during the quarter ended June 30, 2007 as compared to the same period in 2006:

Expenses in respect to exploration activities included in general and administrative expenses, that have been allocated to exploration expense, including third party charges and internal professional staff allocations of $277,172.

Depreciation and depletion expense increased by $702,615 to $1,128,554 for the six months ended June 30, 2007 as compared to the $425,939 incurred during the same period in 2006, due to the higher gas sales volumes in 2007 compared to 2006.

During the six months ended June 30, 2007, we incurred exploration related expenses of $614,802, an increase of $399,540 as compared to the $215,262 incurred during the same period in 2006. The increase is a result of higher expenses incurred for seismic projects on our DJ Basin properties as well as increased exploration activities associated with our future growth plans.

Our expenses in respect to other income (expense) increased by $4,991,779 as a result of $4,629,390 of losses on derivative liabilities and $194,380 of interest accretion associated with the derivative liabilities included in interest expense. In addition, interest expense, including debt issuance amortization expense increased by $151,840. We did not have any debt outstanding as of June 30, 2006. The increase in expense for the 2007 period also included realized gains of $255,900 in respect to natural gas hedging contracts and unrealized losses of $197,647 in respect to those contracts as well. We did not have any hedging contracts in place as of June 30, 2006.

Our interest expense over the term of our $9 million 8% senior subordinated convertible notes will increase substantially due to the significant original issue discount resulting from the application of FAS 133 and the effect of applying the effective interest method. In addition, our derivative expense is subject to adjustment at each reporting period. The amount of charge (or credit) is largely dependent upon assumptions underlying valuation techniques we apply. However, current derivative balances are highly susceptible to changes in our trading market prices. Increases in our trading market prices could result in additional significant charges.

Anticipated Key Third Quarter Items

We plan to consider and pursue additional acquisitions as appropriate based on our business plan as well as to continue to evaluate our Williston Basin and DJ Basin acreage positions. As a result, we will incur additional exploration expenses to evaluate the acreage positions and in respect to additional acquisitions we may incur due diligence and legal expenses, which will be capitalized only if we successfully complete an acquisition. If an acquisition is not successful, we will include those costs in our general and administrative expenses in the period in which such expenses are incurred.

Liquidity and Capital Resources

As of June 30, 2007, we had cash and cash equivalents of $4,039,616 and a working capital deficit of $12,943,982. Of the $12,943,982 working capital deficit, $10,504,980 represents the derivative contract liability of $11,527,200 less the debt issuance costs of $1,022,220 from the fair value of the warrants issued to the placement agent.

On May 16, 2007, the Company closed on $9.0 million of Notes, as earlier described, due May 16, 2008. We received $8.3 million from the issuance of these Notes after fees and expenses. In addition to the Notes, we issued a total of 3,960,000 warrants to purchase our Common Stock at $5.00 per share, including 360,000 warrants issued to the placement agent in conjunction with the Notes.

We currently estimate the cost associated with our Piceance development program to be approximately $22 million for the year ending December 31, 2007. The $22 million represents the drilling costs of 36 wells during 2007 and related infrastructure. Additionally, we estimate that we will spend approximately $8.1 million in the DJ Basin during 2007 for development drilling, gathering lines and other infrastructure, and geological and geophysical programs. We also plan to spend approximately $2.2 million in the Williston Basin during 2007 on drilling and other projects. Our 2007 capital budget could be substantially increased if: (1) Berry, as operator for the Piceance development program, increases the drilling program, (2) Noble, as operator for the DJ Basin development program, increases that drilling program, and (3) Evertson, as operator for the Williston Basin, increases the drilling of our Bakken program.

We anticipate that we will utilize working capital generated from our ongoing operations to meet some of our 2007 commitments. In addition, in March 2006, we filed S-3 and S-4 shelf registration statements for $50 million each in financing capacity, which registration statements have been declared effective by the SEC. On July 25, 2007, we completed a Common Stock offering for 964,060 shares at a price of $5.05 per share for gross proceeds of $4.9 million. The net proceeds after fees and expenses were $4.6 million. The offering included 337,421 warrants to purchase 337,421 shares of Common Stock with an exercise price of $6.06 per share with a 5 year term. Our capacity remaining on the S-3 registration is $34.3 million as a result of our public offering of common stock of $10.8 million during 2006 and the $4.6 million common stock offering completed July 25, 2007. On August 6, 2007, we filed an S-3 registration statement with the SEC for our $9 million of Notes which has not been declared effective as of the date of this report. We received net proceeds of $8.3 million from these Notes, after fees and expenses. We have not utilized any of our $50.0 million S-4 shelf registration.

We also may continue to receive proceeds from the exercise of outstanding warrants and/or options as we did during the year ended December 31, 2006. During the six months ended June 30, 2007, we received $2,018,755 in respect to options that were exercised during the period. As of June 30, 2007 warrants to purchase 4,827,819 shares of Common Stock were outstanding. These warrants have a weighted average exercise price of $4.67 per share and expire between April 2008 and December 2012. As of June 30, 2007, options to purchase 1,523,067 shares of Common Stock were outstanding. These options have a weighted average exercise price of $3.52 per share and expire between July 2007 and May 2015.

In addition to the above, we are currently considering monetizing portions of selected oil and gas properties that we currently own to assist in the funding of our ongoing capital program.

In June 2006, we established a $50 million revolving credit facility with BNP Paribas (the Credit Facility). The Credit Facility had an initial borrowing base of $3.0 million, which was increased to $6.0 million on March 12, 2007 and $10 million on July 19, 2007. The Credit Facility matured on June 15, 2010. As of June 30, 2007, we have an outstanding balance of $6.0 million from the Credit Facility. On August 9, 2007, we announced that JPMorgan Chase Bank, N.A. (JPMorgan Chase) assumed the Credit Facility and we subsequently entered into an amended and restated Credit Facility pursuant to which the initial borrowing base is $14 million with an initial conforming borrowing base of $11 million. The Company s initial advance from JPMorgan Chase was $11 million. This $11 million advance retired the outstanding principal and accrued interest (including related fees to JPMorgan Chase) to BNP Paribas of $10.2 million. The amended and restated Credit Facility contains customary affirmative and negative covenants and is secured primarily by the Company s oil and gas assets. Costs incurred for the amended and restated Credit Facility will be recorded as debt issuance costs and amortized to expense over the life of the agreement. Remaining unamortized debt issuance costs in respect to the Credit Facility will be amortized in full during the third quarter of 2007.

We expect that the combination of our current cash balances, monetization of portions or all of selected oil and gas assets referred to above, amounts available from existing and anticipated increases in our amended and restated Credit Facility, proceeds from the exercise of warrants and options, and the use of our S-3 and S-4 shelf registrations will provide us with adequate resources to meet our capital needs for 2007.

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There can be no assurances that we will be successful in raising capital sufficient to fund the above-referenced capital plan from either the debt or equity markets and or from the monetization of assets in the future, or from increasing our current borrowing base from the Credit Facility.

Sources and Uses of Funds

Historically, our primary source of liquidity has been cash provided by securities offerings. These offerings may continue to play an important role in financing our business. Cash raised from third parties or generated through operations will be used for additional acquisitions or in connection with drilling programs associated with our current properties.

Cash Flows and Capital Expenditures

Operating activities

During the six months ended June 30, 2007, we used $1,618,098 of cash in operating activities, associated with our net loss of $9,045,913 for the period and as follows. We had significant non-cash charges that affected the loss for the 2007 period, including losses on derivative liabilities of $4,629,390, non-cash accrued stock based compensation of $1,792,403, and non-cash depreciation and depletion charges of $1,128,554. In addition, we had non-cash charges that increased our net loss of $197,647 for unrealized loss on natural gas derivative contracts. Additionally, our net cash used in operating activities was reduced as a result of accretion on our 8% senior subordinated convertible notes of $163,001. Offsetting the above items, our cash used in operating activities increased by $793,534 in the 2007 period for cash payments for accrued payroll liabilities and franchise taxes incurred during the year ended December 31, 2006.

During the six months ended June 30, 2006, we used $1,401,648 of cash in operating activities, associated with our net loss of $2,788,971 for the period and as follows. We had significant non-cash charges that affected the loss for the 2006 period, including accrued stock based compensation of $1,038,513, and non-cash depreciation and depletion charges of $425,939. During the 2006 period we used $255,000 of cash in respect to discontinued operations and we used $284,511 in respect to trade accounts receivable. Our cash used in operating activities decreased by $497,324 due to increases in our accounts payable and accrued liabilities.

Investing activities

We incurred capital costs of $14,933,234 and $7,037,981 for the six months ended June 30, 2007 and 2006, respectively. During the 2007 period, we incurred capital costs in respect to our drilling activities of $11,311,965, and costs in respect to facilities of $3,315,269, and in respect to land of $306,000. During the 2006 period, we incurred capital costs both in respect to drilling activities of $4,051,181, in respect to undeveloped leaseholds of $2,466,208, and in respect to facilities of $520,592. As of June 30, 2007, we had 20 Piceance Basin wells in progress compared to 10 Piceance wells in progress as of June 30, 2006. Our development costs have also increased for the six months ended June 30, 2007 as compared to the same period in 2006, due to increased drilling and completion activities in respect to our Piceance and DJ Basins drilling and development programs.

During the six months ended June 30, 2006, we received cash of $2,700,000 in connection with our Acreage Earning Agreement with Noble in respect to our DJ Basin acreage.

Financing activities

During six months ended June 30, 2007, holders of 565,478 options exercised these options and purchased an equivalent number of shares of Common Stock of the Company for net proceeds to us of $2,018,755. During the six months ended June 30, 2006 holders of 629,935 warrants exercised those warrants and purchased shares of Common Stock for net proceeds of $2,869,022 and holders of 350,900 stock options exercised these options and purchased an equivalent number of shares our Common Stock for net proceeds to us of $1,239,732.

During the six months ended June 30, 2007, we drew down $6.0 million on our Senior Bank Credit Facility with BNP Paribas and raised net proceeds of $8.3 million from convertible 8% senior subordinated notes (the Notes) due May 16, 2008. There were no financing transactions for the same period in 2006.

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Commitments

The following outlines our contractual commitments, excluding interest payments, as of June 30, 2007:

	For the six months ended December 31, 2007 and the years ended December 31, 2008, 2009, 2010 and thereafter					
	Remainder of 2007	**2008**	**2009**	**2010**	**Thereafter**	**Total**
8% senior subordinated convertible notes	$	$ 9,000,000	$	$	$	$ 9,000,000
Senior Credit Facility					6,000,000	6,000,000
Operating lease for office space	61,500	129,000	44,000			234,500
Total	$ 61,500	$ 9,129,000	$ 44,000	$	$ 6,000,000	$ 15,234,500

Critical Accounting Policies and Estimates

The following critical accounting policy should be read in conjunction with our critical accounting policies that we included in our Form 10-K for the year ended December 31, 2006, that we filed with the SEC on March 19, 2007.

Derivative Financial Instruments

Derivative financial instruments, as defined in Financial Accounting Standard No. 133, Accounting for Derivative Financial Instruments and Hedging Activities (SFAS 133), consist of financial instruments or other contracts that contain a notional amount and one or more underlying (e.g. interest rate, security price or other variable), require no initial net investment and permit net settlement. Derivative financial instruments may be free-standing or embedded in other financial instruments. Further, derivative financial instruments are initially, and subsequently, measured at fair value and recorded as liabilities or assets. We use derivative financial instruments to hedge exposures to cash-flow risks. In addition, we have also has entered into various types of financing arrangements to fund our business capital requirements, including convertible debt and other financial instruments indexed to our Common Stock. These contracts require careful evaluation to determine whether derivative features embedded in host contracts require bifurcation and fair value measurement or, in the case of freestanding derivatives (principally warrants) whether certain conditions for equity classification have been achieved. In instances where derivative financial instruments require liability classification, we are required to initially and subsequently measure such instruments at fair value. Accordingly, we adjust the fair value of these derivative components at each reporting period through a charge to income until such time as the instruments acquire classification in stockholders equity.

The Company estimates fair values of derivative financial instruments using various techniques (and combinations thereof) that are considered to be consistent with the objective measuring fair values. In selecting the appropriate technique, we consider, among other factors, the nature of the instrument, the market risks that it embodies and the expected means of settlement. For less complex derivative instruments, such as free-standing warrants, to date we have used the Black-Scholes-Merton option valuation technique because it embodies all of the requisite assumptions (including trading volatility, estimated terms and risk free rates) necessary to fair value these instruments. For complex derivative instruments, such as embedded conversion options, we have used to date the Flexible Monte Carlo valuation technique because it embodies all of the requisite assumptions (including credit risk, interest-rate risk and exercise/conversion behaviors) that are necessary to fair value these more complex instruments. For forward contracts that contingently require net-cash settlement as the principal means of settlement, we project and discount future cash flows applying probability-weightage to multiple possible outcomes. Estimating fair values of derivative financial instruments requires the development of significant and subjective estimates that may, and are likely to, change over the duration of the instrument with related changes in internal and external market factors. In addition, option-based techniques are highly volatile and sensitive to changes in the trading market price of our common stock, which has a high-historical volatility. Since derivative financial instruments are initially and subsequently carried at fair values, our income (loss) will reflect the volatility in these estimate and assumption changes.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The price we receive for our oil and natural gas production has a direct influence on our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to fluctuations in response to a variety of factors. The markets for oil and natural gas have experienced periods of high volatility and these markets are likely to experience similar periods of volatility in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on our 2006 production, our income before income taxes for 2006 would have moved up or down approximately $74 thousand for every $0.10 change in natural gas prices.

We have begun entering into derivative contracts to manage our exposure to oil and natural gas price volatility. Our derivative contracts include costless collars and fixed price SWAPS.

On October 24, 2006, we entered into certain ISDA agreements with BNP Paribas to allow us to hedge our commodity pricing risk relative to our future oil and gas production. In addition, we have a company hedging policy in place, if necessary, to protect a portion of our production against future pricing fluctuations. Although we have not yet hedged any of our future production beyond October 31, 2008, we will consider this strategy for future period oil and gas production and future acquisitions.

Our outstanding hedges as of June 30, 2007 are summarized below:

Commodity	**Period**	**Monthly Volume (MMBtu)**	**CIG Floor/Ceiling Or Fixed Per MMBtu**
Costless Collars Contracts:			
Natural Gas	07/2007	30,000	$6.00/$7.25
Natural Gas	08/2007	30,000	$6.00/$7.25
Natural Gas	09/2007	30,000	$6.00/$7.25
Natural Gas	10/2007	30,000	$6.00/$7.25
Natural Gas	11/2007	30,000	$6.00/$7.25
Natural Gas	12/2007	30,000	$6.00/$7.25
Fixed Forward Contract:			
Natural Gas	07/2007	30,000	$5.78
Natural Gas	08/2007	30,000	$5.78
Natural Gas	09/2007	30,000	$5.78
Natural Gas	10/2007	30,000	$5.78
Natural Gas	11/2007	30,000	$5.78
Natural Gas	12/2007	30,000	$5.78
Natural Gas	01/2008	30,000	$5.78
Natural Gas	02/2008	30,000	$5.78
Natural Gas	03/2008	30,000	$5.78
Natural Gas	04/2008	30,000	$5.78
Natural Gas	05/2008	30,000	$5.78
Natural Gas	06/2007	30,000	$5.78
Natural Gas	07/2008	30,000	$5.78
Natural Gas	08/2008	30,000	$5.78
Natural Gas	09/2008	30,000	$5.78
Natural Gas	10/2008	30,000	$5.78

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The costless collared hedges prices shown above have the effect of providing a protective floor while allowing us to share in some upward pricing movements. The fixed SWAP hedge prices have the effect of providing a protective floor with no upward pricing benefit. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases beyond the ceiling or fixed price. For the 2007 natural gas contracts listed above, a hypothetical $0.10 change in the CIG price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the gain (loss) on hedging activities of $66,000. We expect to continue to enter into derivative contracts in order to minimize exposure to commodity price decreases.

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 natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible 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.

On August 10, 2007, we announced that JPMorgan Chase Bank, N.A. (JPMorgan Chase) assumed the BNP Paribas Credit Facility and that we had entered into an amended and restated Credit Facility with JPMorgan Chase. The above listed hedging contracts and the related ISDA agreement were assigned from BNP Paribas to JPMorgan as part of that transaction. See Note 9 Subsequent Events.

Interest Rate Risk

At June 30, 2007, we had $6.0 million outstanding on our Credit Facility. Under the Credit Facility, each loan bears interest at a Eurodollar rate or a base rate, as requested by us, plus an additional margin based on the amount of our total outstanding borrowings relative to the total borrowing base. The Eurodollar rate is based on the London Interbank Offered Rate (LIBOR). The base rate is the higher of the Prime Rate or the Federal Funds Rate plus one-half of one percent. In addition, under the terms of the Credit Facility, we are required to pay a commitment fee based on the average daily amount of the unused amount of the commitment of each lender. This fee accrues at a rate of 0.50% per annum and is paid quarterly in arrears on the last day of March, June, September, and December of each year and on the date on which the Credit Facility is terminated. Assuming that we were to draw down on the entire $6.0 million available to us under our existing BNP Paribas Credit Facility as of June 30, 2007, a one hundred basis point (1.0%) increase in each of the average LIBOR rate and federal funds rate would result in additional interest expense to us of approximately $15,000 per quarter.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934 as of the end of the period covered by this Quarterly Report on Form 10-Q. In designing and evaluating the disclosure controls and procedures, management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of the end of such period, our disclosure controls and procedures are effective to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported on a timely basis.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the quarter ended June 30, 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None.

ITEM 1A. RISK FACTORS

There have been no material changes from risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2006, other than as described below.

If we are unable to obtain additional funding our business operations will be harmed.

We recently received an aggregate of approximately $13,900,000, before expenses and fees, from the sales of certain notes, and shares of Common Stock and warrants, which we intend to use for our 2007 capital expenditure program. In addition to raising funds through the issuance of notes, warrants and shares of our Common Stock, we are pursuing property sales in order to fund our capital program. We will require additional funding to meet increasing capital costs associated with our operations. Based on our operating partners current capital expenditure plans, we will be unable to fund our planned capital program if we are unable to secure additional funding. In addition, although our amended and restated Credit Facility provides availability of up to $50 million, our current borrowing base is only $14 million with a conforming borrowing base of $11 million as of August 9, 2007, and there can be no assurance that our borrowing base will be increased or that additional advances will be made under such credit facility. We do not know if additional financing will be available when needed, or if it is available, if it will be available on acceptable terms. The lack of available future funding may prevent us from implementing our business strategy.

We may incur non-cash charges to our operations as a result of current and future financing transactions.

Under current accounting rules and requirements, we have incurred $5,018,151 of non-cash charges for the three months ended June 30, 2007 beyond the stated contractual interest payments required under our current and potential future financing arrangements. While such charges are generally non-cash, they impact our results of operations and earnings per share and have been and are expected to be material.

We have limited operating control over our properties.

A significant portion of our business activities are conducted through joint operating agreements under which we own partial non-operated interests in oil and natural gas properties, and consequently, we do not have control over normal operating procedures, expenditures, or future development of those underlying properties. Therefore, our operating results for that portion of our business activities are beyond our control. The failure of an operator of our wells to perform operations adequately, or an operator s breach of the applicable agreements, could reduce our production and revenues. In addition, the success and timing of our drilling and development activities on properties operated by others depends upon a number of factors outside of our control, including the operator s timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Since we do not have a majority interest in any of our current properties in which we have a non-operated interest, we may not be in a position to remove the operator in the event of poor performance. Further, significant cost overruns of an operation in any one of our current projects may require us to increase our capital expenditure budget and could result in some wells becoming uneconomic.

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Our failure to achieve and maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act could have a material adverse effect on our business.

We will be subject to Section 404 of the Sarbanes-Oxley Act of 2002 (Section 404) beginning with our annual report on Form 10-K for the period ending December 31, 2007. This will require us to include in our annual reports management s assessments of the effectiveness of our internal controls over financial reporting and a report by our independent auditors that provides the independent auditor s assessment of the effectiveness of our internal controls. Accordingly, we are in the process of documenting and testing our internal control procedures in order to satisfy the requirements of Section 404. We have prepared documentation as to our internal control structure, have added staff to the Chief Financial Officer s department, including a Controller and Chief Accounting Officer, and have developed detailed testing plans that will be implemented during the third and fourth quarters of 2007. However, during the course of our testing, we may identify deficiencies which we may not be able to remediate in time to meet our deadline for compliance with Section 404, and accordingly, we may not be able to conclude on an ongoing basis that we have effective internal controls over financial reporting in accordance with Section 404. In addition, testing and maintaining internal controls also will involve significant costs and can divert our management s attention from other matters that are important to our business. Failure to achieve and maintain an effective internal control environment could harm our operating results, cause us to fail to meet our reporting obligations and could require that we restate our financial statements for prior periods, any of which could cause investors to lose confidence in our reported financial information and cause a decline, which could be material, in the trading price of our Common Stock.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

On May 15, 2007 we issued $9,000,000 of 8% Senior Subordinated Convertible Notes to 10 investors. Each note has a maturity of one year and may be converted into our Common Stock at $5.00 per share. In addition, we issued warrants to purchase 3,600,000 shares to these same investors, with a strike price at $5.00 per share. The warrants have a five year term. No advertising or general solicitation was employed in offering the securities. This transaction was not registered under the Securities Act of 1933, as amended (the Act) in reliance on an exemption from registration under Section 4(2) of the Act based on the limited number of purchasers, their sophistication in financial matters, and their access to information concerning us. Commonwealth Associates, LP served as the placement agent for the transaction. Commonwealth was paid a placement fee of $540,000. In addition, Commonwealth received warrants to purchase 360,000 shares of Common Stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On May 3, 2007, the Company held its annual Shareholder Meeting. The following table outlines the results of the shareholder voting on the proposals included on the Company s Definitive Proxy filed with the SEC on March 19, 2007:

Proposal No. 1 Election of Directors	Vote Type	Voted	Voted (%)
Karl F. Arleth	For	10,382,552	77.41
	Withheld	3,029,580	22.59
Robert F. Bailey	For	12,536,307	93.47
	Withheld	875,825	6.53
John T. Connor Jr.	For	10,372,940	77.34
	Withheld	3,039,192	22.66
Thomas F. Conroy	For	10,276,083	76.62
	Withheld	3,136,049	23.38
William K. White	For	10,360,909	77.25
	Withheld	3,051,223	22.75
James J. Woodcock	For	10,465,297	78.03
	Withheld	2,946,835	21.97
Proposal No. 2 Ratification of Appointment of Auditors			
Ehrhardt Keefe Steiner & Hottman PC	For	13,149,735	98.04
	Withheld	50,920	0.38
	Abstain	211,477	1.58

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS:

4.1	Form of Senior Subordinated Convertible Note.
4.2	Form of Common Stock Purchase Warrant issued to investors in connection with Teton s Senior Subordinated Convertible Notes.
4.3	Form of Common Stock Purchase Warrant issued to investors and placement agents in connection with Teton s July 2007 financing.
10.1	Purchase and Sale Agreement, West Greybull Project, Big Horn County, Wyoming, dated as of April 25, 2007 between Teton, and Melange International LLC, Mike A. Tinker individually and Desert Moon Gas Company, and Hannon & Associates, Inc., as assignors.
10.2	Purchase and Sale Agreement, Oil and Gas Leasehold Purchase, Big Horn County Wyoming, dated as of April 25, 2007 between Teton and Kirkwood Oil and Gas Company.
10.3	Placement Agent Agreement, dated as of May 11, 2007, between Teton and Commonwealth Associates, LP
10.4	Placement Agency Agreement, dated as of July 19, 2007, between Teton, Commonwealth Associates, LP and Ferris, Baker Watts, Incorporated.
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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SIGNATURES

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

	TETON ENERGY CORPORATION
Date: August 14, 2007	By: /s/ Karl F. Arleth Karl F. Arleth President and Chief Executive Officer (Principal Executive Officer)
Date: August 14, 2007	By: /s/ Bill I. Pennington Bill I. Pennington Chief Financial Officer (Principal Financial and Accounting Officer)

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