TETON ENERGY CORP
Form 10-Q
November 14, 2006

U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2006

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 x 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 Act). (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer x

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

As of November 10, 2006, 14,704,759 shares of the issuer s common stock were outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Consolidated Balance Sheets

	September 30, 2006 (Unaudited)	December 31, 2005
Assets		
Current assets		
Cash and cash equivalents	$ 8,318,308	$ 7,064,295
Trade accounts receivable	1,159,101	247,769
Advances to operator	2,125,875	224,429
Tubular inventory	148,628	
Prepaid expenses and other assets	167,420	137,729
Total current assets	11,919,332	7,674,222
Non-current assets		
Oil and gas properties (using successful efforts method of accounting)		
Proved	10,489,861	1,717,213
Producing facilities	200,444	
Unproved	13,851,063	10,636,279
Wells in progress	3,629,775	2,105,884
Facilities in progress	612,500	120,554
Fixed assets	220,449	71,045
Total property and equipment	29,004,092	14,650,975
Less accumulated depreciation and depletion	(1,266,066)	(193,702)
Net property and equipment	27,738,026	14,457,273
Debt issuance costs	193,072	
Total non-current assets	27,931,098	14,457,273
Total assets	$ 39,850,430	$ 22,131,495
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 1,347,899	$ 1,281,457
Accrued liabilities	2,120,591	297,351
Accrued payroll and severance	723,193	396,589
Accrued royalties		94,403
Accrued franchise taxes payable	34,388	62,025
Deposits on sale of assets		300,000
Accrued liability of discontinued operations		255,000
Accrued purchase consideration	2,729,151	
Total current liabilities	6,955,222	2,686,825
Long-term liability		
Asset retirement obligations	39,554	3,851
Total liabilities	6,994,776	2,690,676
Commitments and contingencies		
Stockholders equity		
Common stock, $0.001 par value, 250,000,000 shares authorized, 14,704,759 and 11,329,652 shares issued and outstanding at September 30, 2006 and December 31, 2005, respectively	14,704	11,329
Additional paid-in capital	59,405,468	43,929,216
Accrued stock based compensation	1,521,143	

Accumulated deficit	(28,085,661)	(24,499,726)
Total stockholders equity	32,855,654	19,440,819
Total liabilities and stockholders equity	$ 39,850,430	$ 22,131,495

See notes to unaudited consolidated financial statements

TETON ENERGY CORPORATION

Unaudited Consolidated Statements of Operations and Comprehensive Loss

	For the Three Months Ended September 30, 2006	2005
Oil and gas sales	$ 1,468,892	$ 229,594
Cost of sales and expenses:		
Lease operating expenses	225,904	3,000
Production taxes	100,150	16,086
General and administrative	1,334,162	771,951
Depreciation and depletion	643,083	74,381
Accretion expense from asset retirement obligations	9,389	
Exploration	38,664	216,209
Total cost of sales and expenses	2,351,352	1,081,627
Loss from operations	(882,460)	(852,033)
Other income (expense):		
Interest income	101,609	49,748
Interest expense	(16,113)	
Total other income	85,496	49,748
Net loss	(796,964)	(802,285)
Preferred stock dividend		(12,481)
Net loss applicable to common shares	$ (796,964)	$ (814,766)
Basic and diluted weighted average common shares outstanding	13,883,761	10,578,974
Basic and diluted loss per common share	$ (0.06)	$ (0.08)

See notes to unaudited consolidated financial statements.

TETON ENERGY CORPORATION

Unaudited Consolidated Statements of Operations and Comprehensive Loss

	For the Nine Months Ended September 30, 2006	2005
Oil and gas sales	$ 2,409,375	$ 229,594
Cost and expenses:		
Lease operating expenses	322,227	3,000
Production taxes	171,875	16,086
General and administrative	4,382,907	3,045,691
Depreciation and depletion	1,069,022	84,231
Accretion expense from asset retirement obligations	9,389	
Exploration	253,926	367,089
Total cost of sales and expenses	6,209,346	3,516,097
Loss from operations	(3,799,971)	(3,286,503)
Other income (expense):		
Interest income	230,149	184,018
Interest expense	(16,113)	
Total other income	214,036	184,018
Net loss	(3,585,935)	(3,102,485)
Preferred stock dividend		(61,456)
Net loss applicable to common shares	$ (3,585,935)	$ (3,163,941)
Basic and diluted weighted average common shares outstanding	12,515,384	9,954,057
Basic and diluted loss per common share	$ (0.29)	$ (0.32)

See notes to unaudited consolidated financial statements.

TETON ENERGY CORPORATION

Unaudited Consolidated Statements of Cash Flows

	For the Nine Months Ended September 30, 2006	2005
Cash flows from operating activities		
Net loss	$ (3,585,935)	$ (3,102,485)
Adjustments to reconcile net loss to net cash used in operating activities		
Depreciation and depletion	1,069,022	84,231
Amortization of debt issuance costs	11,722	
Accretion expense from asset retirement obligations	9,389	
Accrued stock based compensation, net of stock returned	1,363,643	
Stock and warrants issued for services and interest		834,775
Changes in assets and liabilities		
Discontinued operations	(255,000)	
Trade accounts receivable	(911,332)	(127,470)
Tubular Inventory	(148,628)	
Advances to operator	(1,901,446)	(226,651)
Prepaid expenses and other current assets	(29,691)	(83,725)
Accounts payable and accrued liabilities	(94,287)	(1,956)
Accrued royalties, franchise taxes payable and payroll and severance	204,564	117,385
	(682,044)	596,589
Net cash used in operating activities	(4,267,979)	(2,505,896)
Cash flows from investing activities		
Proceeds from sale of oil and gas properties	2,700,000	
Purchase of fixed assets	(149,404)	(5,372)
Development of oil and gas properties	(8,974,795)	(1,069,089)
Acquisition of oil and gas properties	(3,486,141)	(8,524,618)
Net cash used in investing activities	(9,910,340)	(9,599,079)
Cash flows from financing activities		
Proceeds from exercise of warrants and issuance of stock, net of issue costs of $0 and $48,862, respectively	4,803,641	2,702,209
Proceeds from issuance of common stock, net of underwriting fees and expenses of $1,126,515 and $0, respectively	10,833,485	
Debt issuance costs from bank debt	(204,794)	
Payment of dividends		(61,456)
Net cash provided by financing activities	15,432,332	2,640,753
Net increase (decrease) in cash and cash equivalents	1,254,013	(9,464,222)
Cash and cash equivalents - beginning of year	7,064,295	17,433,424
Cash and cash equivalents - end of period	$ 8,318,308	$ 7,969,202

See notes to unaudited consolidated financial statements.

	For the Nine Months Ended September 30, 2006	2005
Supplemental Cash Flow Information:		
Non-cash accruals for awards in respect of stock based compensation	$ 1,521,143	$
Reduction in accounting service fees	157,500	
Deposit applied to oil and gas properties Note 1	300,000	
Capital expenditures included in accounts payable or accrued liabilities	1,983,971	173,350
Accrued purchase consideration Note 1	2,729,151	
Common stock and warrants issued for the acquisition of PGR LLC properties		1,088,949
Common stock and warrants issued for the acquisition of DJ Basin properties		792,928
Common stock issued for accounting and legal services		905,625
Common stock issued for settlement of accrued liabilities		10,500
Common stock issued for services by outside directors		39,400
Recorded an asset retirement obligation associated with oil and gas properties	30,165	2,543

See notes to unaudited consolidated financial statements.

TETON ENERGY CORPORATION

Notes to Unaudited Consolidated Financial Statements

Note 1 Organization and Summary of Significant Accounting Policies

Organization

Teton Energy Corporation (the Company, Teton, we, or us) was formed in November 1996 and is incorporated in the State of Delaware. We ar 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.

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 our financial position as of September 30, 2006, the results of operations for the three and nine months ended September 30, 2006, and 2005, and cash flows for the nine months ended September 30, 2006, and 2005. For a more complete understanding of our operations, financial position and accounting policies, these consolidated unaudited financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2005, previously filed with the SEC on March 10, 2006.

In the course of preparing the consolidated financial statements, our 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 and non-cash stock-based compensation expense related to the Company s Long Term Incentive Plan.

Principles of Consolidation

The consolidated financial statements include the accounts of all of our wholly owned subsidiaries. All inter-company profits, transactions, and balances have been eliminated. As is common in the oil and gas industry, we use pro rata consolidation for investments in partnerships and limited liability companies (LLC). In making such determination we will review the LLC operating agreement to determine if the characteristics of the LLC are more like a corporation or more like a partnership.

Inventory Tubular

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

Sale of Oil and Gas Properties

Effective December 31, 2005, we entered into an Acreage Earning Agreement (the Agreement) with Noble Energy, Inc. (Noble), which closed on January 27, 2006. Under the terms of the Agreement, Noble will retain a 75% working interest in our DJ Basin acreage after drilling 20 wells by March 1, 2007 at no cost to us. During that time, we will receive 25% of any net revenues derived from the first 20 wells. After completion of the first 20 wells, we will split with Noble all costs associated with future drilling according to each party s working interest percentage.

Noble paid us $3,000,000 under the agreement and we have 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 our DJ Basin property.

Purchase of Oil and Gas Properties

On May 5, 2006, we closed a definitive agreement with American Oil and Gas, Inc. (American) acquiring a 25% working interest in approximately 59,000 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, we paid American approximately $2.47 million in cash at closing and will pay an additional approximately $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, will be paid to American on that date. In addition to our obligation to fund America s share, we are also obligated to pay costs in respect of our own 25% share of drilling and completion costs of such wells during the same time period.

In addition to our 25% interest, we have two partners in the acreage: American, which has a 50% working interest in the acreage, and Evertson Energy Company (Evertson) who is the operator and has a 25% interest. Evertson began drilling one multi-lateral horizontal well, the Champion 1-25H on September 25, 2006. The estimated cost for the Champion 1-25H is $6.1 million to test the acreage. As of September 30, 2006, we have paid to American $970,162 of the initial obligation of $3.7 million resulting in a remaining accrued purchase consideration of $2.7 million.

Debt Issuance Costs

Debt issuance costs are amortized to interest expense over the life of the related credit facility using the effective interest method.

Revenue Recognition

Oil and natural gas revenue is recognized monthly based on production and delivery. We follow the sales method of accounting for our natural gas and crude oil revenue, so that we recognize sales revenue on all natural gas or crude oil sold to our 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 our revenues.

The volume of natural gas sold may differ from the volume to which we are entitled based on our 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). We have elected to use the sales method. If we used the entitlement method, our future reported revenues may be materially different than those reported under the sales method.

At September 30, 2006, there were no gas imbalances in respect of our gas balancing arrangements.

Successful Efforts Method of Accounting

We account for our 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 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.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory that 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 and an allocation of costs is required properly to account for the results. Delineation seismic 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 the operational results reported when the Company is 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.

Reclassification

Certain amounts in the 2005 financial statements have been reclassified to conform to the 2006 presentation.

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.

Note 3 Revolving Credit Facility

On June 15, 2006, the Company entered into a $50 million revolving credit facility (the Credit Facility) with BNP Paribas as administrative agent, sole lead arranger, and sole book runner. The Credit Facility matures on June 15, 2010.

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 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 has an initial borrowing base of $3.0 million. The borrowing base will be redetermined on a semi-annual basis, based upon an engineering report delivered by us from an approved petroleum engineer. The Credit Facility is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit.

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. 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. Loans made under the Credit Facility are secured by a first mortgage against the Company s properties, a pledge of the equity of our subsidiaries and a guaranty by those same subsidiaries.

Costs were incurred in connection with our Credit Facility and are considered part of our debt issuance costs and are included in our non-current assets. The remaining unamortized debt issuance costs at September 30, 2006 were $193,072. Those debt issuance costs are amortized to interest expense over the life of the related credit facility using the effective interest method.

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. As of September 30, 2006, there were no outstanding balances associated with the credit facility.

Note 4 Stockholders Equity

Our authorized capital stock consists of 250,000,000 shares of common stock, $.001 par value per share and 25,000,000 shares of preferred stock, $.001 par value per share.

During the nine months ended September 30, 2006, 1,125,107 warrants and options were exercised, purchasing an equivalent of number of common shares of the Company for net proceeds to the Company of $ 4,803,641.

In connection with the resignation of our former contract Chief Financial Officer, effective March 31, 2006, 50,000 restricted shares of common stock were returned to us 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.

On June 2, 2005, our Board of Directors declared a dividend distribution of one Preferred Stock Purchase Right (each a Right and collectively the Rights) for each outstanding share of Common Stock, $0.001 par value (Common Stock), of the Company. The distribution was paid as of June 14, 2005 (the Record Date), to stockholders of record on that date. Each Right entitles the registered holder to purchase from the Company one one-hundredth of a share of the Company s Series C Preferred Stock, $0.001 par value at a price of $22.00, subject to adjustment on the occurrence of certain events which generally involve a person acquiring 15% of the Company s Common Stock without the permission of our Board of Directors. The description and terms of the Rights are set forth in the Rights Agreement dated as of June 3, 2005, between the Company and Computershare Investor Services, LLC, as Rights Agent.

On August 2, 2006 we closed a public offering of 2,300,000 shares of our common stock at $5.20 per share. Total shares delivered at closing included the underwriter s over-allotment option to purchase 300,000 additional common shares, which was exercised at closing. Gross proceeds from the offering totaled $11.9 million. Offering costs including the underwriter s fees, legal, accounting and other related expenses totaled $1.1 million. We received net proceeds from the offering of $10.8 million.

Note 5 Stock-based Compensation

At September 30, 2006, we had several stock-based compensation plans, which are more fully described in Note 8 in our Annual Report on Form 10-K for the year ended December 31, 2005.

Accounting Change

Prior to 2006, we accounted for our stock based compensation plans under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25 , Accounting for Stock Issued to Employees (APB 25), and related interpretations, as permitted by Statement of Financial Accounting Standard 123, Accounting for Stock Based Compensation (SFAS No. 123). Effective January 1, 2006, we adopted Statement of Financial Accounting Standard 123R, Share-Based Payment (SFAS No. 123R) which applies to all employee awards granted, modified, or settled after January 1, 2006. SFAS No. 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods and services, focusing primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. It also addresses transactions in which an entity incurs liabilities in exchange for goods and services that are based on the fair value of the entity s equity instruments or that may be settled by the issuance of those equity instruments.

APB 25 did not require any compensation expense to be recorded in the financial statements if the exercise price of the award was not less than the market price on the date of grant. Prior to July 2005, the Company issued only stock options and since all options granted by the Company had exercise prices equal to or greater than the market price on the date of the grant, no compensation expense was recognized for stock option grants prior to January 1, 2006.

SFAS No. 123R requires measurement of the cost of share-based payment transactions to employees at the fair value of the award on the grant date and recognition of expense over the requisite service or vesting period. SFAS No. 123R requires implementation using a modified version of prospective application, under which compensation expense for the unvested portion of previously granted awards and all new awards will be recognized on or after the date of adoption. SFAS No. 123R also allows companies to adopt SFAS No. 123R by restating previously issued financial statements, basing the amounts on the expense previously calculated and reported in their pro forma footnote disclosures required under SFAS No. 123. The provisions of SFAS No. 123R were adopted by the Company effective January 1, 2006, using the modified prospective application method.

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

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
Stock options	$ 4,383	$	$ 24,108	$
LTIP performance share units	199,174		1,137,447	
Restricted common stock	121,574		359,588	834,775
Total	$ 325,131	$	$ 1,521,143	$ 834,775

Stock-based compensation for the nine months ended September 30, 2006 as shown in the table above does not include a credit to expense of $157,500 related to restricted common stock returned to us in connection with the resignation of our former contract Chief Financial Officer.

The Company adopted the disclosure-only provisions of SFAS No. 123 prior to 2006. Accordingly, no compensation cost was recognized in 2005 for stock options. Had compensation cost for stock options been recognized in 2005 based on the fair value at the date of grant, consistent with SFAS No. 123, the Company would have recorded additional compensation expense of $9,863 for both the three and nine months ended September 30, 2005.

Each of the component categories of stock-based compensation is described more fully below.

Stock Options

We granted 45,000 stock options during 2005 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 December 31, 2005, we estimated the unrecognized value of the stock options at $98,625 using the Black-Scholes option-pricing model with the following assumptions: volatility of 109.46%, a risk-free rate of 4%, zero dividend payments and a life of 10 years. The remaining unvested value of the stock options as of December 31, 2005 was revised to $54,791 during the second quarter of 2006, as adjusted for estimated forfeitures. As of September 30, 2006, there were 13,333 unvested stock options outstanding, and the total unrecognized compensation cost adjusted for estimated forfeitures related to non-vested options was $30,683, which is expected to be recognized over the remaining service period of 21 months.

A summary of stock option activity for the nine months ended September 30, 2006 is presented below:

	Number Outstanding (in thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2005	2,875	$ 3.54		
Granted		$		
Exercised	(359)	$ 3.52		
Forfeited or expired	(17)	$ 3.11		
Outstanding at September 30, 2006	2,499	$ 3.53	5.41	$ 3,295
Exercisable at September 30, 2006	2,486	$ 3.53	5.40	$ 3,272

Long Term Incentive Plan

On June 28, 2005, the Company s shareholders approved a long-term incentive plan (the LTIP) that permits the grant of unvested share awards, grants, options, performance share units, and share equivalents 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.

Performance Share Units

The Compensation Committee established 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 Minimum , 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 Minimum 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 Minimum 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 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 we estimate the level of performance expected to be achieved by year-end and record 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). 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) stock price performance over the period 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. The Minimum performance objectives were not achieved for 2005 and none of the initial tranche of 20% of the 2005 Grants was earned in 2005.

In December of 2005 the Compensation Committee established a Pool for 2006 (the 2006 Grant Year) of 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 to 1,250,000 and Stretch Units to 2,500,000 to accommodate expected executive hires. At September 30, 2006, a total of 972,500 Base Units and 1,945,000 Stretch Units had been granted, but not yet earned or vested. The remainder of Units in the 2006 Pool not yet granted will go back into the LTIP and be available for future issuance, consistent with the terms of the LTIP.

The Units 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 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 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.

A summary of the Performance Units as for the nine months ended September 30, 2006 is set forth below:

	2005 Grant Year		**2006 Grant Year**		**Total**	
	Base Performance Share Units (in thousands)	**Weighted Average Grant Date Fair Value**	**Base Performance Share Units (in thousands)**	**Weighted Average Grant Date Fair Value**	**Base Performance Share Units (in thousands)**	**Weighted Average Grant Date Fair Value**
Total pool	400		1,250		1,650	
Grants outstanding at beginning of year	372	$ 4.88		$	372	$ 4.88
Grants during the period	60	$ 5.29	985	$ 6.71	1,045	$ 6.63
Vested and released		$		$		$
Forfeited/cancelled	(92)	$ 4.88	(12)	$ 6.90	(104)	$ 5.11
Outstanding at end of period	340	$ 4.95	973	$ 6.71	1,313	$ 6.25

Restricted Common Stock

In December 2005, grants of 195,000 restricted shares were made pursuant to the Company s LTIP, which vest equally over 3 years, beginning January 1, 2006, based solely on service. An additional 60,000 share grants were made during the first nine months of 2006 of which 55,000 vest over three years and 5,000 vested immediately. Compensation expense was recorded during the nine months ended September 30, 2006 based on the market value of the common stock at the date of grant recorded over the related service period. There was no compensation expense for the nine months ended September 30, 2005 as no Restricted Stock grants were outstanding.

A summary of the status of restricted stock activity granted under our LTIP for the nine month period ended September 30, 2006, is summarized below:

	Restricted Stock (in thousands)	**Weighted Average Grant-Date Fair Value**
Non-vested at December 31, 2005	195	$ 6.06
Granted	60	$ 5.95
Vested	(5)	$ 6.34
Forfeited		$
Non-vested at September 30, 2006	250	$ 6.03

Note 6 Commitments and Contingencies

Mr. Arleth, our President and Chief Executive Officer, signed a new employment agreement on August 30, 2006, which employment agreement became effective as of September 1, 2006. The agreement is for a three-year term, with a base salary of $250,000 per year. Under the terms of the agreement, Mr. Arleth is entitled to 24 months severance pay in the event of a change of position or change in control of the Company. The agreement contains an evergreen provision, which automatically extends the term of Mr. Arleth s agreement for a two-year period if the agreement is not terminated by notice by either party at least 60 days prior to the end of the stated term. In addition, Mr. Arleth will be entitled to a bonus based on his performance against objectives established by our compensation committee each year, and a provision that provides for us to purchase a term split life insurance policy providing for no less than $3,000,000 in benefits, with any such paid benefit to be distributed equally between us and a beneficiary of Mr. Arleth s choosing. In addition, Mr. Arleth s contract includes an indemnification agreement.

Mr. Pennington, our Executive Vice President and Chief Financial Officer, signed an employment agreement on June 1, 2006. The contract provides for an initial salary for Mr. Pennington of $190,000 per year. Under the terms of the agreement, Mr. Pennington is entitled to 12 months severance pay in the event of a change of position or change in control of the Company. The agreement contains an evergreen provision, which automatically extends the term of Mr. Pennington s agreement for a two-year period if the agreement is not terminated by notice by either party at least 60 days prior to the end of the initial stated term which is one year. In addition, Mr. Pennington s contract includes an indemnification agreement.

Mr. Schultz, our Vice President of Production, signed an employment agreement on April 1, 2006. Under the terms of the agreement, Mr. Schultz is entitled to an initial salary of $165,000 per year. The agreement also provides that Mr. Schultz is entitled to six months severance pay in the event of a change of position or change in control of the Company. The agreement contains an evergreen provision, which automatically extends the term of Mr. Schultz s agreement for a two-year period if the agreement is not terminated by notice by either party at least 60 days prior to the end of the initial stated term, which is one year. In addition, Mr. Schultz s contract includes an indemnification agreement.

We have entered into a three-year lease for office space, which expires in April 30, 2009. Contractual commitments under this lease are $28,551 for 2006, $114,204 for 2007, $116,921 for 2008, and $39,880 for 2009.

During 2005, we established a Simple IRA plan, allowing for the deferral of employee income. The plan provides for us to match employee contributions up to 3% of gross awards. For the three months and nine months ended September 30, 2006, we contributed $3,951 and $23,148, respectively to such plan.

Note 7 Subsequent Events

On November 7, 2006, the Company entered into an agreement with an undisclosed third party to acquire approximately 56,000 gross acres, 42,000 net acres, of which a significant portion lies within Chase and Dundy Counties, Nebraska. The terms of the purchase were not disclosed but not considered financially material to the Company s interest. Approximately 33,600 net acres (80 percent) lie within the Noble Energy, Inc. (Noble) and the Company s Area of Mutual Interest (AMI) and will be offered to Noble under the terms of the AMI. Approximately 8,400 net acres (20 percent) are outside the AMI and are currently held with a 100 percent working interest net to Teton. The agreement is expected to close by December 15, 2006 and is subject to due diligence.

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 anticipated trends in revenues, 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, 2005, under the subsection Caution 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 Discussion And Analysis

Overview

Teton Energy Corporation (the Company, Teton, we, or us) was formed in November 1996 and is incorporated in the State of Delaware. We a 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 September 30, 2006

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

Financial and operational highlights for the three months ended September 30, 2006 include the following:

- Our net loss decreased to $796,964 ($0.06 per share) for the three month period ended September 30, 2006 from $814,766 ($0.08 per share) for the same period in 2005. The lower net loss for the 2006 quarter from the 2005 quarter was a result of higher sales of gas in the Piceance Basin of Colorado.

- Our revenue from the sale of natural gas was $1,468,892, which is based on the sale of 300,627 mcf of natural gas at an average price of $4.89 per mcf after a total deduction of $158,676 ($0.53 per mcf) for gathering, fuel, transportation and marketing expenses, net to the Company.

- We participated in the drilling of five wells in the current quarter to total depth on our acreage in the Piceance Basin of Colorado. We also completed ten wells and put them on production in the quarter.

- On September 25, 2006, we spud our first well in the Williston Basin located in North Dakota (Champion 1-25H).

- We participated in the drilling of 10 wells as part of the initial pilot program with Noble Energy, Inc. on our over 182,000 gross acreage block. We will be carried for our 25 percent working interest on the first 20 wells with Noble. Four of the wells were drilled in the Chundy prospect area located in Chase and Dundy Counties, Nebraska. One well was logged, cased and waiting on completion, two wells were perforated and fractures stimulated and one well was plugged and abandoned. The remaining six wells were drilled in the Grant prospect area located in Grant County, Nebraska. Two wells were logged, cased and are waiting on completion, two wells were perforated and fractures stimulated and two wells were plugged and abandoned.

- On August 2, 2006, we closed on a public offering of 2,300,000 shares of our common stock, which was priced on July 27, 2006 at $5.20 per share. Petrie Parkman & Co., served as the sole underwriter and book-running manager for the offering. Total shares delivered at closing included the underwriter s over-allotment option to purchase 300,000 additional common shares, which was exercised at closing. As a result of the underwriter s exercise of its over-allotment option, net proceeds of the offering were $10.8 million.

Results of Operations for the Three Months Ended September 30, 2006

We had a net loss for the three months ended September 30, 2006, of $796,964, which is $17,802 less than the net loss for the same period in 2005. The decreased net loss for the third quarter of 2006 compared to the prior period in 2005 was primarily due to an increase in gas sales $1,239,298 less the higher 2006 cost of sales and expenses of $1,269,725.

During the three months ended in September 30, 2006, oil and gas sales, net to our interest, totaled 300,627 mcf resulting in $1,468,892 in oil and gas sales, at an average price of $4.89 per mcf after a total deduction of $158,676 ($0.53 per mcf) for gathering, fuel, transportation and marketing expenses for the 2006 quarter. During the three months ended in September 30, 2005, oil and gas sales net to our interest totaled 38,339 mcf resulting in $229,594 in oil and gas sales, at an average price of $5.99 per mcf after a total deduction of $38,499 ($1.00 per mcf) for gathering, fuel, transportation and marketing expenses for the 2005 quarter. The increase in gas sales resulted primarily from the increase in the number of wells under production in 2006 as compared with 2005.

Lease operating expenses and production tax expenses for the three-month period ended September 30, 2006, were $225,904 and $100,150, respectively, (or a total of 22% of sales or $1.08 per mcf) net to us resulting in operating income from oil and gas activities of $1,142,838 ($3.80 per mcf) before depreciation and depletion, accretion expense, exploration costs, general and administrative expenses, and other income. Lease operating expenses and production tax expenses for the three-month period ended September 30, 2005, were $3,000 and $16,086 respectively, (or a total of 8% of sales or $0.50 per mcf) net to us resulting in operating income from oil and gas activities of $210,508 ($5.49 per mcf) before depreciation and depletion, exploration costs, general and administrative expenses, and other income. The increase in lease operating expenses and production taxes resulted primarily from the increase in the number of wells under production in 2006 as compared with 2005.

During the third quarter of 2006, general and administrative expense increased from $771,951 during 2005 to $1,334,162, a $562,211 increase which is primarily due to an increase in non-cash charges as described in greater detail below. Significant changes in the increase to general and administrative expenses for the three months ended September 30, 2006 compared to 2005 include:

• An increase in compensation expense of approximately $442,136, which increase was due primarily to $325,131 of non-cash compensation accruals of stock-based grants as a result of the performance estimates associated with our long-term incentive plan and our adoption of Statement of Financial Accounting Standard 123R Share-Based Payment, effective as of January 1, 2006. Also, compensation increased $117,005 as a result of an increase in the number of employees from 2005 and bonus accruals for 2006 associated with the growth in our operations.

• Consulting expenses increased $115,197 for engineering, marketing, investor relations and financial services rendered in 2006 from 2005.

• Board of directors fees increased $41,935 from the prior year due primarily to two additional members and higher fees in 2006.

During the three-month period ended September 30, 2006; certain general and administrative expenses were lower than in the prior year three-month period:

• Legal and accounting, decreased by approximately $49,851 from the prior year period in 2005 as a result of decreased accounting costs associated with contracting its CFO and accounting services.

During the third quarter of 2006, exploration expenses were $177,545 lower than the prior year s quarter, primarily due to the timing of delay rental payments on our DJ Basin properties.

Depreciation and depletion expense increased from $74,381 in the third quarter in 2005 to $643,083 in the same quarter in 2006 due to the higher gas production in 2006 compared to none in 2005.

Other income in 2006 includes interest income from the cash balances maintained.

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Results of Operations for the Nine Months Ended September 30, 2006

We had a net loss for the nine months ended September 30, 2006, of $3,585,935, which is $421,994 more than the net loss for the same period in 2005. The increased loss was primarily due to an increase in non-cash stock-based compensation and stock and warrants issued for services of $528,868 from the nine months ended September 30, 2005 to the same period in 2006. We also experienced higher sales, lease operating expenses, general and administrative expenses and depreciation and depletion expenses in the nine months ended September 30, 2006 than in the same period 2005, as discussed below. The overriding causes of increased sales and expenses were increases in the number of wells on production and increased operating activity.

During the nine months ended in September 30, 2006, oil and gas sales net to our interest totaled 477,160 mcf resulting in $2,409,375 in oil and gas sales, at an average price of $5.05 per mcf after a total deduction of $303,254 ($0.64 per mcf) for gathering, fuel, transportation and marketing expenses for the first nine months of 2006. During the nine months ended in September 30, 2005, oil and gas sales net to our interest totaled 38,339 mcf resulting in $229,594 in oil and gas sales, at an average price of $5.99 per mcf after a total deduction of $38,499 ($1.00 per mcf) for gathering, fuel, transportation and marketing expenses for the first nine months of 2005. The increase in gas sales resulted primarily from the increase in the number of wells under production in 2006 as compared with 2005.

Lease operating expenses and production taxes for the nine-month period ended September 30, 2006, were $322,227 and $171,875, respectively (or a total of 21% of revenues or $1.04 per mcf) net to us resulting in operating income from oil and gas activities of $1,915,273 ($4.01 per mcf) before depreciation and depletion, exploration costs, general and administrative expenses, and other income. Lease operating expenses and production tax expenses for the nine-month period ended September 30, 2005, were $3,000 and $16,086, respectively (or a total of 8% of revenues or $0.50 per mcf) net to us resulting in operating income from oil and gas activities of $210,508 ($5.49 per mcf) before depreciation and depletion, exploration costs, general and administrative expenses, and other income. The increase in lease operating expenses and production taxes resulted primarily from the increase in the number of wells under production in 2006 as compared with 2005.

During the nine months ended September 30, 2006, general and administrative expense of $4,382,907 increased $1,337,216 from $3,045,691 for the comparable period during 2005. Significant increases in general and administrative expenses for the nine months ended September 30, 2006, compared to 2005 include:

- Compensation expense increased approximately $2.1 million, which increase was due primarily to $1,521,143 of non-cash compensation accruals of stock-based grants as a result of the implementation of our long-term incentive plan and our adoption of SFAS 123R, Share-Based Payment, effective as of January 1, 2006 and an increase of $583,296 from 2005 to 2006 due to an increase in the number of employees and bonus accruals associated with such employee growth.

- Office expenses increased by approximately $137,716 due to larger office space and office furniture and supplies due to increased operational and administrative activity.

- Stock transfer and listing fees increased $86,213 from the prior year due to the shelf registrations filed in the first quarter of 2006.

- Consulting expenses increased $55,176 for engineering, marketing, investor relations and financial services rendered in 2006 from 2005.

During the nine-month period ended September 30, 2006; certain general and administrative expenses were lower than in the prior year nine-month period:

- Legal and accounting decreased by approximately $948,523 from the prior year period in 2005 as a result of decreased legal and accounting costs. Accounting and legal costs included non-cash restricted stock issued of $798,000 in 2005. There was no restricted stock issued for accounting and legal costs in 2006.

During the nine months ended September 30, 2006, exploration expenses decreased $113,163 from 2005 primarily due to the timing of delay rental payments on our DJ Basin properties.

Depreciation and depletion expense increased $984,791 for the nine months ended September 30, 2006 from the same prior 2005 period due to the higher gas sales in 2006 compared to 2005.

Other income in 2006 includes interest income from the cash balances maintained.

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Anticipated and Completed Key Third Quarter Items

We plan to consider and pursue additional acquisitions as appropriate based on our business plan. As a result, 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 year in which such expenses are incurred.

On August 2, 2006, we closed on a public offering of 2,300,000 shares of our common stock, which was priced on July 27, 2006 at $5.20 per share. Total shares delivered at closing included the underwriter s over-allotment option to purchase 300,000 additional common shares, which was exercised at closing. As a result of the underwriter s exercise of its over-allotment option, net proceeds of the offering were $10.8 million.

Liquidity and Capital Resources

We had cash and cash equivalents of $8,318,308 at September 30, 2006, and a working capital surplus of $4,964,110.

We have revised our 2006 drilling and completion capital commitment to approximately $14.3 million net to the Company s interest. This revised commitment includes our proportionate costs associated with the drilling of up to 20 total wells (depending on rig availability and other factors) and our proportionate costs relative to the various infrastructure projects and construction of an access road on the Piceance Basin acreage. We also anticipate that we could incur potential additional expenditures relating to gathering systems on our DJ Basin acreage of $750,000 (net to the Company s interest), as drilling results become known. Also included in the total $14.3 million is $1.55 million net to the Company s interest for capital requirements in respect of our commitment to drilling one well.

We anticipate that we will utilize working capital generated from our ongoing operations in the Piceance Basin, DJ Basin and Williston Basin to meet some of our 2006 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. As discussed above, we closed on a public offering of 2,300,000 shares of its common stock; with net proceeds of the offering were $10.8 million. As a result of the offering, we have $39 million of financing capacity remaining on our S-3 shelf registration. We have not utilized any of our S-4 shelf registration.

We may also receive proceeds from the exercise of outstanding warrants and/or options as we did during the nine months ended September 30, 2006. At November 1, 2006, warrants to purchase 867,819 shares of common stock were outstanding. These warrants have a weighted average exercise price of $3.14 per share and expire between April 2008 and December 2012. At November 1, 2006, options to purchase 2,499,434 shares of common stock were outstanding. These options have a weighted average exercise price of $3.53 per share and expire between July 2007 and May 2015.

In June 2006, we established a $50 million revolving credit facility with BNP Paribas (the Credit Facility). The Credit Facility has a current borrowing base of $3 million and matures on June 15, 2010. 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 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 borrowing base will be redetermined on a semi-annual basis, based upon an engineering report delivered by us from an approved petroleum engineer. The Credit Facility is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit.

There are no assurances that we will be successful in raising capital from either the debt or equity markets in the future.

Sources and Uses of Funds

Historically, our primary source of liquidity has been cash provided by equity 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

During the nine months ended September 30, 2006, we used $682,044 of cash in our operating activities. This amount compares to $596,589 of cash generated in our operating activities during the nine month period in 2005. The decrease of net cash used in our operating activities of $1,278,633 was primarily due to an increase in the changes in advances to operator and an increase in trade accounts receivable of $1,674,795 and $783,862, respectively offset by increases in depreciation and depletion expense of $984,791 and in stock based compensation and stock and warrants issued for services of $528,868.

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During nine months ended September 30, 2006 we received cash of $2,700,000 in connection with the entering into the Acreage Earning Agreement with Noble involving our DJ Basin acreage. During the same period, we incurred costs of $8,974,795 primarily related to our drilling and completion operations in the Piceance Basin and $3,486,141 primarily due to the unproved property acquisition in the Williston Basin.

During nine months ended September 30, 2006, holders of 760,957 warrants exercised these warrants and purchased an equivalent number of common shares of the Company for net proceeds to us of $3,538,251, and holders of 359,150 stock options exercised these options and purchased an equivalent under of common shares of the Company for net proceeds to us of $1,265,390. For the nine months ended September 30, 2006, we raised $4,803,641 from the combined sale of options and warrants.

On October 24, 2006, the Company 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 an approved 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, we will consider this strategy for oil and gas production and future acquisitions.

Income Taxes, Net Operating Losses and Tax Credits

Since our inception, we have generated a net operating loss (NOL) carryforward for U.S. income tax purposes. Such NOL is subject to U.S. Internal Revenue Code Section 382 limitations. For losses incurred prior to 2005, utilization of the NOL is limited to approximately $900,000 per annum.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in the Notes to our consolidated financial statements. In response to SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, we have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas reserves, bad debts, oil and gas properties, marketable securities, income taxes, derivatives, contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements.

Our Critical Accounting Policies and Estimates are included in our Form 10-K filed with the SEC on May 10, 2006

Reserve Estimates

Estimates of oil and gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretations and judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover gas costs, all of which may vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Impairment of Oil and Gas Properties

We review our oil and gas properties for impairment whenever events and circumstances indicate a decline in their carrying value. We estimate the expected future cash flows of our developed proved properties and compare such future cash flows to the carrying values of the proved properties to determine if the carrying value is recoverable. If the carrying value exceeds the estimated undiscounted future cash flows, we will adjust the carrying value of the oil and gas properties to their fair value. The factors used to determine fair value include, without limitation, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected.

Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that would require us to record an impairment of the carrying values associated with oil and gas properties.

Stock Compensation

Effective January 1, 2006, we adopted the provisions of SFAS 123R to account for stock based compensation. Previously, we accounted for this compensation under the provisions of APB 25. Under APB 25, stock options did not result in any charge to earnings if the exercise price on the date of grant equaled or exceeded fair value (market price) on the grant date. Stock grants were charged to earnings on the vesting date based upon the market price of the stock on the date of the grant.

Under SFAS 123R, accounting for stock grants has not changed materially. We now accrue for anticipated vesting of stock grants in interim reporting periods based upon our best estimates at the time of the interim period of the conditions and criteria under which the options will vest. These conditions and criteria include service through the vesting date, announced future terminations, performance criteria based upon most recent forecasts and market conditions where appropriate. The estimates used are subjective and based upon managements judgment and may change over time as experience emerges. Changes to the interim accruals due to changes in the estimates of the conditions and criteria are recorded in the period in which the estimate changes occur.

During the quarter ended September 30, 2006, we recorded current compensation of $325,131 based on our Compensation Committee s current assessments of the progress being made in the satisfaction of performance and service conditions for these awards that could vest at year end 2006, provided the milestones are achieved. The performance assessment is scored based on an evaluation of the degree of progress made in achieving each of Minimum, Base, and Stretch objectives established by the Compensation Committee of our Board of Directors by year end. Our compensation expense will increase or decrease in subsequent quarters based on management s progress toward the achievement of these objectives. Improved performance during the subsequent quarters of the year will increase compensation expense in those quarters whereas diminished performance will reduce compensation expense in subsequent quarters. The ultimate compensation expense for the year will reflect our actual performance and its associated vesting of the particular LTIP tranche.

The portion of the stock compensation expense pertaining to Performance Share Units under the Company s LTIP for the nine months ended September 30, 2006 was $1,137,447 based upon estimated annual expense of $1,516,596. We recorded expense for the six months ended June 30, 2006 of $938,273 based upon estimated annual expense of $1,876,546. We decreased the amount of the estimated annual expense by $359,950 as a result of lower estimates of expected achievement of performance objectives.

Under SFAS 123R, our accounting for stock options has changed. We now amortize the unvested portion of stock option grants over the vesting period at the fair value of the option, as described in Note 5 to the financial statements. At September 30, 2006, there were 13,333 option grants unvested.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in 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.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas and oil production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for natural gas and oil production has been volatile and unpredictable in past years, and we expect this

volatility to continue in the future. The prices we receive for production depend on many factors outside of our control. For the three months ended September 30, 2006, our income before income taxes, including hedge settlements, would have changed by $30,063 for each $0.10 per mcf change in natural gas prices. During the three months ended September 30, 2006, we had no oil production.

On October 24, 2006, the Company 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 an approved 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, we will consider this strategy for oil and gas future production and acquisitions.

Interest Rate Risk

At September 30, 2006, we had no debt 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. Although there are currently no outstanding borrowings against the Credit Facility, a one hundred basis point (1.0%) increase in each of the average LIBOR rate and federal funds rate would have resulted in an estimated $7,500 increase in interest expense on a quarterly basis, assuming we were to draw down on the entire amount of our borrowing base of $3 million.

ITEM 4. 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 nine months ended September 30, 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

None.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS:

10.1 First Amendment to Credit Agreement dated as of November 1, 2006 among Teton Energy Corporation, as Borrower, the Guarantors, BNP Bank Paribas, as Administrative Agent and The lenders party hereto

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 Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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: November 14, 2006	By:	/s/ Karl F. Arleth Karl F. Arleth President and Chief Executive Officer
Date: November 14, 2006	By:	/s/ Bill I. Pennington Bill I. Pennington Chief Financial Officer (Principal Financial and Accounting Officer)