TETON ENERGY CORP
Form 10-K
March 05, 2009

Table of Contents

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

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2008

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE TRANSITION PERIOD FROM _____ TO _____
COMMISSION FILE NUMBER 1-31679
TETON ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	**84-1482290**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
600 17th Street, Suite 1600 North Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code: **(303) 565-4600**
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, par value $0.001	NASDAQ Capital Market

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Act). Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III or this Form 10-K or any amendment to this Form 10-K. o

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

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

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

The aggregate market value of the common stock held by non-affiliates of the issuer, as of June 30, 2008, was approximately $103,116,269, based on the closing bid of $4.99 for the issuer s common stock as reported on the American Stock Exchange, the exchange on which the issuer s shares were formerly listed. Shares of common stock held by each director, each officer and each person who owns 10% or more of the outstanding common stock have been excluded from this calculation in that such persons may be deemed to be affiliates. The determination of affiliate status is not necessarily conclusive.

As of February 25, 2009 the issuer had 23,894,749 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13 and 14 of Part III is incorporated by reference from portions of the registrant s definitive proxy statement relating to its 2009 annual meeting of stockholders to be filed within 120 days after December 31, 2008.

FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2008
INDEX

Table of Contents

The terms Teton , Company , we , our and us refer to Teton Energy Corporation and its subsidiaries, as a consolidated entity, unless the context suggests otherwise. We have included technical terms important to an understanding of our business under Glossary on page 18 and in Items 1 and 2, Business and Properties , of this Form 10-K.

Forward-Looking Statements

This report as well as other documents we file with the Securities and Exchange Commission (the SEC) may contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact, are or may be forward-looking statements. For example, statements concerning projections, predictions, expectations, estimates or forecasts, and statements that describe our objectives, future performance, plans or goals are, or may be, forward-looking statements. These forward-looking statements reflect management s current expectations concerning future results and events and can generally be identified by the use of the words may, will, should, could, would, likely, predict, potential, continue, future, estimate, believe, expect, an plan, project, foresee and other similar words or phrases, as well as statements in the future tense.

In addition, our senior management may make forward-looking statements in print or orally to analysts, investors, the media and others. These statements are based on management s current expectations and information currently available and are believed to be reasonable and are made in good faith. However, the forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those projected in the statements. Factors that may cause actual results to differ from expected include, but are not limited to:

- General economic and political conditions, including constrained credit markets, tax rates or policies, inflation rates and governmental energy policies;
- Our ability to access capital markets;
- The market price of, and supply/demand for, oil and natural gas;
- Our ability to service our existing and future indebtedness;
- Our ability to meet bank covenants on our outstanding indebtedness;
- Our ability to replace our reserves;
- Our success in completing development and exploration activities;
- Our ability to maintain an adequate borrowing base on our bank credit facility;
- Reliance on outside operating companies for drilling and development of our non-operated oil and gas properties;
- Our ability to pursue and integrate acquisitions into our company structure;
- Changes in laws and regulations; and
- Other Risk Factors described in Item 1A of this Annual Report on Form 10-K.

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

Forward-looking statements are only as of the date they are made and we do not undertake any obligation to update publicly any forward-looking statement either as a result of new information, future events or otherwise except as required by applicable laws and regulations.

Table of Contents

PART I

ITEMS 1. and 2. BUSINESS and PROPERTIES.

Background

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

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

Our principal executive offices are located at 600 17th Street, Suite 1600 North, Denver, CO 80202, and our telephone number is (303) 565-4600. Our web site is *www.teton-energy.com.*

Overview and Strategy

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

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

The pursuit of our strategy includes the following key elements:

Pursue Attractive Reserve and Leasehold Acquisitions

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

Drive Growth through Drilling

We plan to supplement our long-term reserve and production growth through drilling operations. In 2008, we participated in the drilling of 17 gross operated wells in connection with our Central Kansas Uplift, 52 gross wells in our non-operated Piceance Basin property and 112 gross wells in our non-operated Teton-Noble AMI. In response to the current economic turmoil and credit crisis, we have reduced our drilling program in 2009 and will focus primarily on limited development drilling of our operated properties in the Central Kansas Uplift. Initially, we will target a drilling program that maintains the current production levels in CKU in 2009, but we may adjust the approach throughout the year based upon positive or negative shifts in the capital markets or commodity prices.

Maximize Operational Control

It is strategically important to our future growth and maturation as an independent exploration and production company to be able to serve as operator of our properties when possible in order to be able to exert greater control over costs and timing in, and the manner of, our exploration, development and production activities. We currently have eight projects; five operated by the Company and three operated by other companies. As mentioned above, our strategic plan involves focusing on the development of our operated properties.

Operate Efficiently and Effectively, and Maximize Economies of Scale Where Practical

Our objective is to generate profitable growth and high returns for our stockholders, and we expect that our unit cost structure will benefit from economies of scale as we grow and from our continuing cost management initiatives. As we manage our growth, we are actively focusing on reducing lease operating expenses and finding and development costs. In addition, our acquisition efforts are geared toward pursuing opportunities that fit well within existing operations, in areas where we are establishing new operations or in areas where we believe that a base of existing production will produce an adequate foundation for economies of scale.

Pursuit of Selective Complementary Acquisitions

We seek to acquire long-lived producing properties with a high degree of operating control, or oil and gas concerns that enjoy good business reputations and that offer economical opportunities to increase our natural gas and crude oil reserves.

As an example of this strategy, on April 2, 2008, we completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas from Shelby Resources, LLC, a private oil and gas company and a group of approximately 14 other working interest owners, collectively (the Sellers) for approximately $53.6 million. Terms include warrant coverage of 625,000 shares at a $6.00 strike price with a two-year term. The effective date of the transaction was March 1, 2008.

The purchase price was funded with $40.2 million of cash, $13.0 million of Teton common stock, or 2,746,128 common shares, and 625,000 warrants valued at $434. Effective April 2, 2008, we amended our bank credit facility with JPMorgan, increasing the total facility from $50 million to $150 million (the Amended Credit Facility). The available borrowing base under the Amended Credit Facility was increased from $10 million to $50 million ($34.5 million at December 31, 2008, as discussed in Note 6 of the Notes to the Consolidated Financial Statements) as a result of the combination of the added reserves from this transaction, ongoing drilling programs and new hedging positions. We hedged 80 percent of the estimated oil proved developed producing (PDP) production and 80 percent of the estimated natural gas PDP production related to this transaction for five years through a series of costless collars in order to lock in base case economics associated with the acquisition. At December 31, 2008, we have 100% of the then-current oil production volumes hedged (see further discussion under Hedge Contracts below).

Operations, Properties and Recent Events

As of December 31, 2008, we had estimated proved reserves of 16.9 Bcf of natural gas and 1,558 MBbl of oil, or a total of 26.2 Bcfe, with a PV-10 value of $28.2 million (see reconciliation, and our definition, of the PV-10 non-GAAP financial measure to the standardized measure under Reserves beginning on page 10). Of these reserves, 69% are proved developed, with 36% being crude oil and 64% being natural gas. This represents a net increase in reserve volumes of 106%, but only a 1% increase in the PV-10 value from the prior year, due to pricing decreases for reserve calculation purposes of $41.50 per barrel of crude oil and $1.43 per Mcf of natural gas. Our reserve estimates change continuously and are evaluated by us annually. Changes in the market price of oil and natural gas, as well as the effects of production, acquisitions, dispositions and exploratory development activities may have a significant effect on the quantities and future values of our reserves.

During 2008, we invested $35.3 million in capital expenditures related to exploration and development. For 2009, we have budgeted approximately $10.5 million for drilling, geological and geophysical studies, facilities and land costs. We plan to participate in the drilling of up to 38 gross wells and in the completion or recompletion of 19 wells drilled prior to 2009. In our operated Central Kansas Uplift properties, we plan to drill up to 33 gross wells and recomplete 9 existing wells. In our non-operated Piceance Basin, our partner has indicated that it intends to complete three of the 20 wells drilled in 2008 which had not been completed by year end and recomplete an additional six of 14 wells that have additional production potential. In our non-operated Williston Basin, we are participating in the completion of the Viall #1-30 well drilled to test the Stonewall, Red River and Winnipeg formations on our Goliath acreage block. Red Technology Alliance, LLC (RTA) whom we signed an agreement with in the third quarter to rill from one to four horizontal wells to test the Bakken formation on our Goliath acreage block at no cost to us, has notified us that it intends to renegotiate the terms of the existing agreement due to low

4

Table of Contents

commodity prices. Currently, if all four wells are drilled, our working interest will be reduced from 25 to 15 percent in the Bakken formation. In our operated Big Horn Basin, we plan to drill and complete one well during 2009. We have received a permit to drill our first well to test the Greybull Sandstone. We have signed an agreement with a third party whereby they will pay for 90 percent of the cost of the Greybull well to casing point (as well as 60 percent of the first Mowry well to casing point) in order to earn a 50 percent working interest in our Big Horn acreage block. We have no plans to participate in the drilling of new wells, during 2009, in the Teton-Noble AMI or our operated DJ Basin properties.

We continually evaluate new opportunities, and if an additional opportunity is identified that complements our business objectives we will pursue the opportunity if we believe the economics are favorable and its pursuit will not compromise our financial and human resources. We will review and revise our 2009 capital budget on a periodic basis.

Recent adverse developments in equity and credit markets have made it more difficult and more expensive to access capital markets. Although the capital markets tightened in the latter half of 2008, we believe that the amounts available to us under our existing $150 million credit facility ($34.5 million borrowing base at December 31, 2008) together with the anticipated net cash provided by operating activities during 2009 and proceeds from potential sales of non-operated properties will provide us with sufficient funds to develop new reserves, maintain our current facilities, complete our limited capital expenditure program and meet our debt obligations through 2009. As of December 31, 2008, we owned interests in a total of 315 producing wells and had an interest in 921,911 gross acres (488,294 net) with over 1,350 prospective locations in what we believe are hydrocarbon prone basins of the Midcontinent and Rocky Mountains.

As of December 31, 2008, our estimated acreage holdings by basin are:

Basin	Gross Acres	Net Acres
Central Kansas Uplift*	55,260	36,396
Piceance	6,314	789
DJ		
Noble AMI	330,152	68,789
Frenchman Creek*	31,912	13,939
S. Frenchman Creek*	122,802	120,598
Washco*	254,884	205,484
Williston	88,472	16,346
Bighorn*	32,115	25,953
Total	921,911	488,294

* Represents properties that are either currently operated by us or which are expected to be operated by us when development commences on the properties.

We intend to grow our reserves and production through our current areas of exploration and development, which are as follows:

Central Kansas Uplift

On April 2, 2008, we completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift, and we began recognizing our share of production from the 53 producing wells at that time. We closed on April 2, 2008, and formally took over operations at the end of April, retaining the prior owner on a contract for advisory services through the end of 2008 in order to take advantage of its significant expertise in the area. During 2008, we spud 18 wells, of which ten have been determined to be economically viable producing wells and two others were completed as salt water disposal wells. Pipe has been run on nine producing wells encountering both the Arbuckle and the Lansing/Kansas City oil and one gas well is waiting on hookup.

In the past, we have been using outside resources to select the drilling locations, which concentrated on selected areas of the acreage. We have now added geological and geophysical professionals to our staff and believe that such additional staff, coupled with analysis of 3D seismic activities that have been performed over the past several months, will increase our success rate in Kansas. The historical success rate on this property has been approximately 68%, and we believe that we can return to something close to that level of results. During 2009, we plan to drill 33 gross wells and do nine recompletions in Kansas.

Based on the wells we have successfully drilled to date, the average well has come on production at about 30-35 BOPD with a 30,000-35,000 barrel EUR. In the fourth quarter of 2008, we drilled a well that came on production at 92 BOPD with a 90,000 barrel EUR. We are currently completing a 24.6 square mile 3D seismic shoot in an area which has an expected EUR of 50,000-55,000 barrels. In addition, there are five productive horizons in the area of the 3D seismic which should increase the expected drilling success factor. Several potential locations have already been identified within the 3D area.

Our historical average per well drilling and completion costs for CKU have been $360,000. Based on service company rates currently being negotiated, we believe that costs will be under $300,000 in 2009. At December 31, 2008, we had approximately 100% of the current oil PDP production hedged on costless collars at a floor price of $90 per barrel (and a ceiling price of $104 per barrel) for January 1, 2009 through April 30, 2013. The hedges on this oil decline monthly as the estimated PDP curve declines. At $90 per barrel of oil, a 35,000 barrel EUR (and $360,000 drilling and completion costs per well, a typical well in the project has generated a 90% IRR. For new wells drilled, we will receive the posted field price for the oil, since all of the volumes under the costless collar hedges are committed to current production. At a realized price of $34 per barrel (which approximates the price in this area in February 2009) to Teton, a 42,000 barrel EUR well and $300,000 drilling and completion costs per well, a typical well in the project will generate a 31% IRR.

Between April 2, 2008 and December 31, 2008 the 62 gross producing wells produced a total of approximately .9 Bcfe (141 MBbls of oil and 54 MMcf of natural gas), net to our interest.

Piceance Basin

Teton s properties in the Piceance Basin originally consisted of a 25% working interest (19.69% net revenue interest) in a 6,314-acre block located in Garfield County, Colorado, immediately to the northwest of Grand Valley gas field, the westernmost of the four gas fields that comprise the continuous, basin-centered, tight gas sand accumulation (the Piceance Fairway).

On October 1, 2007, we completed the sale of one-half of the 25% working interest in the Piceance assets for $40 million, after post-closing adjustments. We purchased the original acreage for approximately $4,000 per acre and realized approximately $48,000 per acre on this sale. After the sale, we have a 12.5% working interest in the 6,314 gross acres (789 net).

These properties are in the vicinity of major gas production from continuous basin-centered, tight gas sand accumulations within the Williams Fork formation of the Upper Cretaceous Mesaverde group and the shallower Lower Tertiary Wasatch formation. The primary targets for drilling on this large acreage position are the 1,500 -2,500 thick, gas-saturated sands of the middle and lower Williams Fork formation at approximately 6,000 -9,000 in depth. In addition, to the northwest of the block is the Trail Ridge gas field (Wasatch and Mesaverde). To the west, south, and east are gas wells of the greater Grand Valley field.

As of December 31, 2008, we have an interest in 95 gross producing wells, which produced a total of approximately 1.3 Bcfe, net to our interest, during the twelve months ended December 31, 2008. During 2008, 52 wells were drilled, with 30 of those wells being completed. This is a true resource play, with all wells drilled to date finding economically viable reserves. Our 2009 capital budget provides for the completion of an additional three of 20 wells drilled in 2008, which were not completed at year end, and the recompletion of an additional six out of 14 wells with additional production potential. The planned completions will take place in 2009 once the winter weather subsides. The number of wells drilled, completed or recompleted and the timing of such operations are determined by the operator, Berry Petroleum Co.

DJ Basin

Teton Noble AMI

We acquired our first interest in this play through a series of transactions between April 2005 and July 2005 that resulted in our accumulating in excess of 182,000 gross acres. In December 2005, we entered into an Acreage Earning Agreement (Earning Agreement) with Noble Energy, Inc. (Noble), under which Noble paid us $3 million and earned a 75% working interest in our DJ Basin acreage after drilling and completing 20 wells, at no cost

6

Table of Contents

to us. Pursuant to the Earning Agreement, we retained a 25% working interest in the AMI created by the Earning Agreement, and both parties shared all costs at each individual s respective percentages going forward.

The drilling target of this play is primarily the Niobrara formation, within which is trapped biogenic gas in the Beecher Island Chalk of the Upper Cretaceous Niobrara formation. The gas is contained in shallow structural traps at depths ranging from 1,700-2,500 feet. The acreage is located approximately 20 to 30 miles to the east of the main Niobrara gas productive trend that has been established to the west in Yuma, Phillips, and Sedgwick Counties, Colorado, and in Duell and Garden Counties, Nebraska.

During the twelve months ended December 31, 2008, we recognized impairment expense related to our non-operated properties in the Teton-Noble AMI of $11.8 million. During 2008, we received and signed AFEs for a total of 105 wells in the Teton-Noble AMI. During the fourth quarter of 2008, we notified the operator of our election to go non-consent on the remaining 2008 drilling program for two reasons: (1) we wanted time to evaluate the results of adding pumping units to existing production to bring the production volumes up to economic levels, and (2) we believe it is more prudent to retain the funds that would be expended for additional new wells in this area while we are in these times of credit and capital market constraints and lower commodity prices. Noble agreed with our approach and has informed us that they will not drill any additional wells in the Teton Noble-AMI until the production issues are resolved. The results of these wells have been disappointing for the amount of investment made to date. The gathering system problems that are being addressed by the operator are resulting in marginal economics for the project, and we intend to exercise our right to go non-consent until the volume-related problems are resolved.

As of December 31, 2008, we have an interest in 124 gross producing wells, which, during the twelve months ended December 31, 2008, produced a total of approximately 244 MMcfe, net to our interest.

Frenchman Creek

The initial Frenchman Creek acreage block, 31,912 gross acres (13,939 net), is located in Phillips County, Colorado, in the eastern DJ Basin. In 2008, we entered into an agreement with Targe Energy Exploration and Production, LLC (Targe) whereby Targe carried us on two pilot wells and Targe s proportionate share of 3-D seismic to earn a 50 percent interest in the acreage block. The initial test wells targeted the Niobrara Beecher Island Chalk Interval, which is gas-bearing in fields in close proximity to our new well locations, at a depth of about 2,500 feet. The first two wells were not commercially viable. We believe that the Frenchman Creek prospect contains multiple Niobrara structures, which were identified by our 3-D seismic evaluations of the area. We have staked and permitted an additional nine locations for Niobrara test wells. Based on current service company rates, as well as our past drilling experience in the Teton-Noble AMI, we expect the gross drilling and completion costs for a Niobrara well at Frenchman Creek to approximate $220,000. Based on conservative engineering estimates, we believe we can drill at least 45 additional wells on the 31,912 acre block with an estimated average 200 MMcfe ultimate recovery per well. However, as noted above, the current state of the world economy and the industry commodity pricing preclude us from planning any additional wells in Frenchman Creek in 2009 at this time.

South Frenchman Creek

In November 2008, we acquired bolt-on acreage (contiguous to our current acreage) in the DJ Basin that allowed us to establish a new operating area of 122,802 gross acres (120,598 net) in Yuma County, Colorado, southern Dundy County, Nebraska and northwestern Cheyenne County, Kansas. The acreage is in proximity to existing Niobrara gas production and deeper Lansing-Kansas City oil production.

Based on current service company rates as well as our past drilling experience in the Teton Noble AMI, we anticipate that gross drilling and completion costs for a Niobrara gas well in this portion of Frenchman Creek are approximately $220,000 and for a Lansing-Kansas City oil well are approximately $296,000 at the present time. Based on conservative engineering estimates, we believe we can drill at least 300 gas wells and 30 oil wells on the 120,598 net acre block with an estimated average 200 MMcfe ultimate recovery per gas well and 30,000-60,000 barrel ultimate recovery per oil well. We are currently seeking partners to pursue the possibility of drilling Lansing-Kansas City oil wells on this acreage.

Table of Contents

Washco

As part of the sale of a one-half interest in our Piceance properties (see comments under Piceance Basin above), we acquired a large, contiguous block of acreage in the DJ Basin. As of December 31, 2008, we have an interest in approximately 254,884 gross acres (205,484 net) primarily in Washington and Yuma Counties, Colorado. The acreage is southwest of our existing acreage in the DJ Basin the Teton Noble AMI and Frenchman Creek Prospect areas. The drilling targets of this play are the Niobrara formation for gas, and the J and D sands for oil. The gas is contained in shallow structural traps at depths ranging from 1,700-2,500 feet. The oil is contained either in four-way structural traps or stratigraphic traps with depths ranging from 4,300-4,500 feet.

During the twelve months ended December 31, 2008, the 27 gross producing wells produced a total of 319 MMcfe (39 MBbl of oil and 87 MMcf of gas) net to our interest. After we produce an additional 47 MBbl of oil, the oil production reverts to its previous owner and will cease to be included in our operations.

Williston Basin

On May 5, 2006, we acquired a 25% working interest from American Oil and Gas, Inc. (American) in approximately 87,192 gross acres in the Williston Basin located in Williams County, North Dakota, which has grown to 88,472 gross acres (16,346 net). In addition to our 25% working interest and American s 50% working interest, we have two other partners in the acreage: Evertson Energy Company (Evertson), which is the operator and has a 20% working interest, and Sundance Energy, Inc., which has a 5% working interest.

The targets of this prospect are the oil of the Mississippian Bakken formation of the Williston Basin and the natural gas of the Red River formation. This Bakken shale produces from horizontal wells at a depth of approximately 10,500 feet. The lateral legs will vary from 3,000 to 9,000 feet in length. Although the primary area with notable production from the Bakken is in Richland County, Montana, several wells have been completed directly to the east and south of the acreage block. Multiple stage fracture stimulation is being used to increase recoveries. Secondary horizons in this area include the Duperow, Nisku, Mission Canyon and Sanish formations.

On November 13, 2008 we and our partners spud the Viall #30-1 well in our Goliath project in the Williston Basin to test the Stonewall, Red River and Winnipeg formations, and the drilling rig was released on December 16, 2008 and moved off location on December 22, 2008. Completion operations commenced on January 5, 2009. As of February 25, 2009, testing of the Winnipeg formation did not indicate commercially viable production from that formation, but the Red River C and D formations tested positive for commercially viable reserves. The well is waiting on pipeline connection to a gas processing facility.

The first of four locations in the Bakken Shale play, subject to a participation agreement with Red Technology Alliance LLC (RTA) on Teton s 88,472 gross acreage block, was originally expected to be spud in the first quarter of 2009. RTA has notified us that they intend to renegotiate the terms of the existing agreement due to low commodity prices. In accordance with the participation agreement, RTA will carry us on up to four wells, at their election, in order to earn up to a 40-percent working interest in the project, which would change our working interest from 25% to 15%.

Based on current service company rates as well as past drilling experience in the Williston Basin Bakken and Red River formations, we anticipate that gross drilling and completion costs for a Bakken well are approximately $3.8 million and for a Red River well are approximately $3.7 million. Based on currently approved field spacing rules (640 acres for Bakken, 320 acres for Red River) and the results of 3D seismic work done on the Red River formation in 2008, we believe we could possibly drill up to 180 Bakken wells and up to approximately 10 Red River wells on the 88,472-acre block with an estimated average 258 MBO ultimate recovery per Bakken well and an estimated average 3.9 Bcfe ultimate recovery per Red River well.

At December 31, 2008, we had 8 gross producing wells which produced a total of 72.5 MMcfe (10 MBbl of oil and 10.7 MMcf of gas) net to our interest during the twelve months ended December 31, 2008.

Table of Contents

Big Horn Basin
In 2007, we acquired 16,417 gross acres (15,132 net), which has grown to 32,115 gross acres (25,953 net), in our operated Big Horn Basin of Wyoming. The Greybull and Peay Sand formations are conventional oil and gas targets for this play and the Mowry Shale is an unconventional horizontal gas target. During 2008 we permitted our first well to test the Greybull Sandstone and drilling is expected to commence during the second half of 2009 due to Bureau of Land Management winter and wildlife stipulations.

Based on current service company rates, we anticipate that gross drilling and completion costs for a Greybull well are approximately $2.7 million and for a Mowry well are $4.0 million. Based on currently approved field spacing rules (320 acre spacing for Greybull and 640 acre spacing for Mowry), we believe we could drill approximately 99 Greybull and 62 Mowry wells on the 32,115-acre block.

Other Recent Developments

On May 16, 2008, we repaid $6.6 million of the $9.0 million face value of 8% Senior Subordinated Convertible Notes that closed on May 16, 2007 (the Notes). The remaining $2.4 million was converted to 480,000 shares of our common stock at a conversion price of $5.00 per share. In a separate transaction, on October 7, we and all of the investors who held the 3,600,000 warrants and 360,000 warrants issued to placement agents (issued in connection with the May 2007 financing transaction) agreed to exchange the warrants for 990,000 shares of our common stock. As a result, the carrying value of the current liability for the 3,600,000 financing warrants was reduced to the fair value as of the date of the exchange and we recognized a gain of $7.8 million as a result.

On June 18, 2008, we closed on the private placement of $40 million aggregate principal amount of 10.75% Secured Convertible Debentures due on June 18, 2013 (the Debentures). The holders each had a 90-day put option, expiring September 18, 2008, whereby they elected to reduce their investment in the Debentures by a total of 25% of the face amount, or $10 million in the aggregate. We repaid the $10 million to our investors on September 18, 2008, reducing the total outstanding amount on the Debentures to $30 million. The net proceeds from the issuance of the Debentures, after fees and related expenses (and excluding the 90-day 25% put options) were approximately $28 million. These funds were used to pay down our outstanding indebtedness on our revolving credit facility. On November 13, 2008, one of our investors, who held a $3.75 million investment in the 10.75% Secured Convertible Debentures, elected to convert, bringing the total outstanding amount on the Debentures to $26,250,000. We issued 576,924 shares of our common stock (based on the $6.50 stated conversion rate), 216,541 shares of our common stock related to the interest make-whole provision and paid $893,000 in cash related to accrued interest through the conversion date and for the remaining amount of the interest make-whole. The total cost to us was approximately $1.7 million, or $2.05 million less than the outstanding amount of the debt that was converted.

In connection with the privately placed 10.75% Secured Convertible Debentures, the borrowing base on our $150 million revolving credit facility was reduced from $50 million to $32.5 million. On August 1, 2008 the borrowing base was re-determined and increased to $34.5 million (on November 1, 2008, the borrowing base was reaffirmed at $34.5 million). The balance outstanding on the revolving credit facility at December 31, 2008 was $29,650,000.

During the twelve months ended December 31, 2008, we recognized impairment expense, under SFAS No. 144, related to our non-operated properties in the Teton-Noble AMI of $11.8 million and in the operated Washco properties in the DJ Basin of $2.4 million. During 2008, we received and signed AFEs for a total of 105 wells in the Teton-Noble AMI. During the fourth quarter of 2008, we notified the operator of our election to go non-consent on the remaining 2008 drilling program for two reasons: (1) we want time to evaluate the results of adding the pumping units to existing production to bring the production volumes up to economic levels, and (2) we believe it is more prudent to retain the funds that would be expended for additional new wells in this area while we are in these times of credit and capital market constraints and lower commodity prices. Noble agreed with our approach and has informed us that they will not drill any additional wells in the Teton Noble-AMI until the production issues are resolved. The results of these wells have been disappointing for the amount of investment made to date. The gathering system problems that are being addressed by the operator are resulting in marginal economics for the project, and we intend to exercise our right to go non-consent until the volume-related problems are resolved.

Subsequent to December 31, 2008 and prior to the date of this filing, we retired an additional $750,000 of our privately placed 10.75% Secured Convertible Debentures for approximately $273,000, or $0.36 on the dollar. Giving effect to this transaction, the amount outstanding on our 10.75% Secured Convertible Debentures was reduced to $25,500,000.

Table of Contents

Reserves

The reserve estimates at December 31, 2008, 2007 and 2006 presented below were reviewed by the independent petroleum engineering firm Netherland, Sewell and Associates, Inc. All reserves are located within the continental United States. For the periods presented, Netherland, Sewell and Associates, Inc. evaluated 100% of the properties included in our reserves. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by Teton. Reserve estimates are inherently imprecise and are continually subject to revisions based on production history, results of additional exploration and development, prices of oil and gas, and other factors. The SEC recently adopted a final rule amending its oil and gas reporting requirements, to be effective for the annual report for our fiscal year ending December 31, 2009. These revisions, among other things, call for the use of a 12-month average price rather than the price on the last day of the fiscal year. For purposes of the estimates below, the old rules are still in effect. For more information regarding the inherent risks associated with estimating reserves, see Item 1A, Risk Factors.

	As of December 31,		
	2008	2007	2006
	(dollars in thousands)		
roved developed oil reserves (Bbls)	1,443,782	112,173	
roved undeveloped oil reserves (Bbls)	114,119	16,396	
otal proved oil reserves (Bbls)	1,557,901	128,569	
roved developed gas reserves (Mcf)	9,484,586	7,929,988	4,927,429
roved undeveloped gas reserves (Mcf)	7,396,191	5,377,520	2,165,629
otal proved gas reserves (Mcf)	16,880,777	13,307,508	7,093,058
otal proved gas equivalents (Mcfe) (1)	26,228,183	14,078,922	7,093,058
resent value of estimated future net cash flows before income taxes, discounted at 10% (2)	$ 28,233	$ 27,992	$ 8,705
econciliation of non-GAAP financial measure:			
V-10 (3)	$ 28,233	$ 27,992	$ 8,705
ess: Undiscounted income taxes			
lus: 10% discount factor			
iscounted income taxes			
tandardized measure of discounted future cash flows	$ 28,233	$ 27,992	$ 8,705

(1) Oil is converted to Mcfe of gas equivalent at six Mcfe per barrel.

(2) The present value of estimated future

net cash flows as of each date shown was calculated using oil and gas prices being received by each respective property as of that date.

(3) Our standardized measure of discounted future cash flows assumes no future income taxes will be paid as a result of our cumulative net operating loss carryforwards. As a result, the normal reconciling items between the non-GAAP financial measure of PV-10 and our standardized measure of discounted future net cash flows are zero.

As a reference, the December 31 CIG Rocky Mountains spot market price and Plains Marketing, L.P. West Texas Intermediate posted price for 2008 and Plains Marketing, L.P. Wyoming Southwestern Area posted price for 2007 utilitized for December 31, 2008, 2007, and 2006, respectively, were $4.61 per Mcf and $41.00 per barrel of oil; $6.04 per Mcf and $82.50 per barrel of oil; and $4.46 per Mcf.

The table above also shows our reconciliation of our PV-10 to our standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with GAAP). PV-10 is our estimate of the present value of future net revenues from estimated proved oil and natural gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their present value. We believe PV-10 to be an important measure for evaluating the relative significance of our oil and natural gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual

Table of Contents

company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP. Reference should also be made to the Supplemental Oil and Gas Information included in Item 8, Financial Statements and Supplementary Data , Note 12 to the Consolidated Financial Statements for additional information.

Production Data

The table below sets forth certain production data for the fiscal years ended December 31, 2008, 2007 and 2006. Additional oil and gas disclosures can be found in Item 8, Financial Statements and Supplementary Data, Note 12 of the Consolidated Financial Statements.

	Years Ended December 31,		
	2008	2007	2006
Total gross oil production, Bbls	671,534	40,528	
Total gross gas production, Mcf	14,383,312	6,745,225	3,744,379
Net oil production, Bbls	192,437	16,575	
Net gas production, Mcf	1,657,728	1,127,568	737,175
Average oil sales price after realized hedging results, $/Bbl	$ 92.03	$ 74.81	$
Average gas sales price after realized hedging results, $/Mcf	$ 7.30	$ 5.49	$ 5.46
Average production cost ($/Mcfe)	$ 2.93	$ 1.44	$ 1.45

The following table summarizes our ownership interest in productive wells:

	As of December 31,		
	2008	2007	2006
Gross productive wells			
Oil	72	12	
Gas	243	120	20
Total	315	132	20
Net productive wells (1)			
Oil	60.63	9.37	
Gas	64.26	35.13	5.00
Total	124.89	44.50	5.00

(1) Net well count is based on Teton s effective net interest as of the end of each year.

11

Table of Contents

Wells Drilled

The following table sets forth the number of wells drilled and completed during the last three fiscal years:

	Years Ended December 31,					
	2008		2007		2006	
	Gross	Net (1)	Gross	Net (1)	Gross	Net (1)
Exploratory						
Oil	6	0.25	3	0.33		
Gas			13	3.25		
Dry Holes	2	1.00			4	1.00
Total	8	1.25	16	3.58	4	1.00
Development						
Oil	9	7.13				
Gas	102	19.90	90	18.38	20	5.00
Salt Water Disposal	2	2.00				
Dry Holes	25	9.42	13	3.13		
Total	138	38.45	103	21.51	20	5.00
Total						
Oil	15	7.38	3	0.33		
Gas	102	19.90	103	21.63	20	5.00
Salt Water Disposal	2	2.00				
Dry Holes	27	10.42	13	3.13	4	1.00
Total	146	39.70	119	25.09	24	6.00

(1) Net well count is based on Teton s effective net working interest as of the end of each year.

Finding and Development Costs

During the year ended December 31, 2008, we increased our gross proved reserves by 15.0 Bcfe from the level at December 31, 2007. During the same period, we expended $71.8 million in finding (including acquisitions) and development costs, defined as acquisition, development and exploration costs incurred by the Company during 2008. This activity resulted in a one year finding and development cost in 2008 of $4.79 per Mcfe. Finding and development costs per Mcfe is determined by dividing our annual acquisition, development and exploration costs incurred on projects completed during the year by gross proved reserve additions, including both developed and undeveloped reserves added during the current year (gross amounts, not net of production and sales of properties). We use this measure as one indicator of the overall effectiveness of acquisition, exploration and development activities. Proved reserves were added in each of 2008, 2007 and 2006 through our development drilling activities.

Our finding and development cost per Mcfe measure has certain limitations. Consistent with industry practice, our finding and development costs have historically fluctuated on a year-to-year basis based on a number of factors including the extent and timing of new discoveries and property acquisitions. Due to the timing of proved reserve additions and timing of the related costs incurred to find and develop our reserves, our finding and development costs per Mcfe measure often includes quantities of reserves for which a majority of the costs of development have not yet been incurred. Conversely, the measure also often includes costs to develop proved reserves that had been added in earlier years. Finding and development costs, as measured annually, may not be indicative of our ability economically to replace oil and natural gas reserves because the recognition of costs may not necessarily coincide with the addition of proved reserves. Our finding and development costs per Mcfe may also be calculated differently than the comparable measure for other oil and gas companies.

Table of Contents

Acreage

The following table sets forth the total gross and net acres of developed and undeveloped oil and gas leases in which Teton had working interests as of December 31, 2008:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Central Kansas Uplift*	9,378	9,378	45,882	27,018	55,260	36,396
Piceance Basin	3,640	455	2,674	334	6,314	789
DJ Basin						
Noble AMI	16,322	2,511	313,830	66,278	330,152	68,789
Frenchman Creek*			31,912	13,939	31,912	13,939
S. Frenchman Creek*			122,802	120,598	122,802	120,598
Washco*	1,080	894	253,804	204,590	254,884	205,484
Williston Basin	1,399	210	87,073	16,136	88,472	16,346
Big Horn Basin*			32,115	25,953	32,115	25,953
Total	31,819	13,448	890,092	474,846	921,911	488,294

* Represents properties that are either currently operated by us or which are expected to be operated by us when development commences on the properties.

Hedge Contracts

We have entered into various contracts to hedge our exposure to the fluctuating cash flows due to changing oil and natural gas prices. The duration of our current and future hedging contracts depends on our view of the market conditions, available contract prices and our operating strategy at the time the contracts are initiated. As of December 31, 2008, we had hedging contracts in place for 100% of our current Kansas daily oil production (99% of total oil production) and none of our daily gas production:

Type of Contract	Remaining Volume	Fixed Price per Barrel	Price Index (1)	Remaining Period
Oil Costless Collar	143,545	$90.00 Floor/$104.00 Ceiling	WTI	01/01/09-12/31/09
Oil Costless Collar	106,876	$90.00 Floor/$104.00 Ceiling	WTI	01/01/10-12/31/10
Oil Costless Collar	87,920	$90.00 Floor/$104.00 Ceiling	WTI	01/01/11-12/31/11
Oil Costless Collar	79,611	$90.00 Floor/$104.00 Ceiling	WTI	01/01/12-12/31/12
	25,192		WTI	01/01/13-04/30/13

Oil Costless Collar		$90.00 Floor/$104.00 Ceiling
Total Bbl	443,144	

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

Title to Properties

Substantially all of our working interests are held pursuant to leases from third parties. A title opinion is usually obtained prior to the commencement of drilling operations on properties. We have obtained title opinions or conducted a thorough title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. The majority of the value of our properties is subject to mortgages under our credit facility and our 10.75% Secured Convertible Debentures, customary royalty interests, liens for current taxes and other burdens that we believe do not materially interfere with the use of or affect the value of such properties. We also perform a title investigation before acquiring undeveloped leasehold interests.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and warmer summer months but decrease during the spring and fall months (shoulder months). Pipelines, utilities,

Table of Contents

local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter and summer requirements during the shoulder months, which can lessen seasonal demand fluctuations.

We sometimes enter into hedging contracts for a portion of our production, which reduces our overall exposure to seasonal demand and resulting commodity price fluctuations. At December 31, 2008, we have no gas hedging contracts in place.

Marketing and Major Customers

The principal products produced by us are natural gas and crude oil, which products are marketed and sold primarily by the third party operators of our non-operated wells and a third party marketing company. Typically, oil is sold at the wellhead at field-posted prices and natural gas is sold under contract at negotiated prices based upon factors normally considered in the industry (such as distance from well to pipeline, pressure and quality).

The sale of most of our gas was to Berry during the years ended December 31, 2008, 2007 and 2006, accounting for 28%, 77% and 92%, respectively, of our total oil and gas sales. Plains Marketing, L.P. accounted for 97% and 79% of our oil sales, and 62% and 16% of our total oil and gas sales, in the years ended December 31, 2008 and 2007, respectively. We had no material oil sales prior to 2007. Although a substantial portion of our production is purchased by two customers, we do not believe the loss of any one customer, or both customers, would have a material adverse effect on our business as other customers would be readily accessible to us.

Competition

The oil and gas industry is extremely competitive, particularly in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Our competitive position also depends on our geological, geophysical and engineering expertise, and our financial resources. We believe that the location of our leasehold acreage, our exploration, drilling and production expertise and the experience and knowledge of our management and industry partners enable us to compete effectively in our current operating areas.

Governmental Regulation

Our business and the oil and natural gas industry in general are heavily regulated. The availability of a ready market for natural gas production depends on several factors beyond our control. These factors include regulation of natural gas production, federal and state regulations governing environmental quality and pollution control, the amount of natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities, and the marketing of competitive fuels. State and federal regulations generally are intended to prevent waste of natural gas, protect rights to produce natural gas between owners in a common reservoir and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state, and local agencies.

We believe that we and our operating partners are in substantial compliance with such statutes, rules, regulations and governmental orders, although there can be no assurance that this is or will remain the case. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on our industry increases our cost of doing business and affects our profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted so we are unable to predict the future cost or impact of complying with such laws and regulations.

The following discussion of the regulation of the United States oil and natural gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations and environmental orders to which our operations may be subject.

Regulation of Oil and Natural Gas Exploration and Production

Our oil and natural gas operations are subject to various types of regulation at the federal, state and local levels. Prior to commencing drilling activities for a well, we (or our operating subsidiaries, operating entities or operating partners) must procure permits and/or approvals for the various stages of the drilling process from the applicable federal, state and local agencies in the state in which the area to be drilled is located. Such permits and approvals include those for drilling wells, and such regulation includes maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and, therefore, it may be more difficult to develop a project if an operator owns less than 100% of the leasehold. In addition, state conservation laws may establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and natural gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and reinterpreted, we are unable to predict the future cost or impact of complying with such regulations.

Split Estate Regulation and Access Difficulties

Frequently, the mineral estate and the surface estate are owned by separate parties (the split estate), so that the surface owner is not receiving the monetary benefit of production from minerals underlying his lands. Although the mineral owner and its lessee (such as Teton) are entitled to use so much of the surface as is reasonably necessary to explore for and produce the minerals, many states have laws which grant the surface owner increased control over the nature and extent of surface use which the oil and gas operator may exercise. Legislation to give the surface owner greater control over use of the surface by the oil and gas operator is pending in several states. In addition, due to the increasing value of surface estates in many areas, the costs to obtain access over such surfaces are increasing.

Natural Gas Marketing, Gathering and Transportation

Federal legislation and regulatory controls have historically affected the price of natural gas and the manner in which production is transported and marketed. Under the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (FERC) regulates the interstate sale for resale of natural gas and the transportation of natural gas in interstate commerce, although facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated natural gas prices for all first sales of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, FERC has granted to all producers such as us a blanket certificate of public convenience and necessity authorizing the sale of gas for resale without further FERC approvals. As a result, all natural gas that we produce in the future may now be sold at market prices, subject to the terms of any private contracts that may be in effect.

Natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation, because the prices that companies such as Teton receives for their production are affected by the cost of transporting the gas to the consuming market. Through a series of comprehensive rulemakings, beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, FERC has adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of gas to the primary role of gas transporters and by increasing the transparency of pricing for pipeline services. FERC also has developed rules governing the relationship of the pipelines with their marketing affiliates and implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants, and most pipelines have also implemented the large-scale divestiture of their gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines thus now generally provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. Sellers and buyers of gas have gained direct access to the particular pipeline services they need, and are better able to conduct business with a larger number of counterparties.

Table of Contents

Environmental Regulations

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stricter environmental legislation and regulations could continue. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, our business and prospects could be adversely affected.

The nature of our business operations results in the generation of wastes that may be subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The U.S. Environmental Protection Agency (EPA) and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our operations or operations through our operating partners that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Stricter standards in environmental legislation may be imposed on the industry in the future. For instance, legislation has been proposed in Congress from time to time that would reclassify certain exploration and production wastes as hazardous wastes and make the reclassified wastes subject to more stringent handling, disposal and clean-up restrictions. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as on the industry in general. Compliance with environmental requirements generally could have a materially adverse effect on our capital expenditures, earnings or competitive position.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the present or past owners or an operator of the disposal site or sites where the release occurred and the companies that transported or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Furthermore, although petroleum, including natural gas and crude oil, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA and thus such wastes may become subject to liability and regulation under CERCLA. State initiatives further to regulate the disposal of crude oil and natural gas wastes are also pending in certain states and these various initiatives could have adverse impacts on our business.

Our operations may be subject to the Clean Air Act (the CAA) and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have been developing regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues.

The Federal Water Pollution Control Act (the FWPCA or the Clean Water Act) and resulting regulations, which are implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure strictly to comply with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies.

However, regulatory agencies could require us to cease construction or operation of certain facilities that are the source of water discharges and compliance could have a materially adverse effect on our capital expenditures, earnings, or competitive position. The Energy Policy Act of 2005 specifically exempted fracturing fluids from regulation as underground injection under the Safe Drinking Water Act, provided that diesel fuel is not used in the fracturing fluid. However, there is talk of repealing that exemption.

Our operations are subject to local, state and federal laws and regulations to control emissions from sources of air pollution. Payment of fines and correction of any identified deficiencies generally resolve penalties for failure strictly to comply with air regulations or permits. Regulatory agencies also could require us to cease construction or operation of certain facilities that are air emission sources. We believe that we are in substantial compliance with the emission standards under local, state, and federal laws and regulations.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including the risk of fire, explosions, above-ground and underground blowouts, craterings, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as gas leaks, ruptures and discharges of toxic gas, the occurrence of any of which could result in our suffering substantial losses due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Our pipeline, gathering and distribution operations are subject to the many hazards inherent in the natural gas industry. These hazards include damage to wells, pipelines and other related equipment, and surrounding properties caused by hurricanes, floods, fires and other acts of God, inadvertent damage from construction equipment, leakage of natural gas and other hydrocarbons, fires and explosions and other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

Any significant problems related to our facilities (including jointly owned facilities) could adversely affect our ability to conduct our operations. In accordance with customary industry practice, we maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant event not fully insured against could materially adversely affect our operations and financial condition. We cannot predict whether insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

Employees and Office Space

As of December 31, 2008, we had 30 full time employees. Our employees are not covered by a collective bargaining agreement. We lease 13,941 square feet of office space in Denver, Colorado, from an unaffiliated third party. The term of our lease is 69 months, and the lease expires on July 31, 2014.

Available Information

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to reports filed or furnished pursuant to Sections 13(a) and 15(d) of the Securities Exchange Act of 1934, as amended, are available on our website at *http://www.teton-energy.com*, as soon as reasonably practicable after we electronically file such reports with, or furnish those reports to, the Securities and Exchange Commission. Our Reports and amendments to reports are available free of charge by writing to:

Teton Energy Corporation
Ron Wirth, Director of Investor Relations and Administration
600 17th Street, Suite 1600 North
Denver, CO 80202

We maintain a code of ethics applicable to our Board of Directors, principal executive officer and principal financial officer, as well as all of our other employees. A copy of our Code of Business Conduct and Ethics and our Whistleblower Policy may be found on our website at *http://www.teton-energy.com*, under the Corporate Governance section. These documents are also available in print to any stockholder who requests them. Requests for these documents may be submitted to the above address.

Our filings are also available to the public over the Internet at the SEC s web site at http://www.sec.gov (SEC File No. 1-31679), or at the SEC s public reference room located at 100 F. Street, N.E., Washington, D.C. 20549. Copies of these documents may be requested by writing to the SEC and paying a fee for the copying cost. Information about the public reference room is available by calling the SEC at 1-800-SEC-0330.

Table of Contents

Glossary

Within this report, the following terms and conventions have specific meanings:

3-D seismic Seismic data that are acquired and processed to yield a three-dimensional picture of the subsurface.

AMI Area of Mutual Interest.

Basin A depressed sediment-filled area, roughly circular or elliptical in shape, sometimes very elongated. Regarded as a potentially good area to explore for oil and gas.

Big Horn Basin A geologic depression in North Central Wyoming approximately 100 miles wide located in Big Horn, Washakie, Park and Hot Springs counties.

Cash flow hedge A derivative instrument that complies with Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and is used to reduce the exposure to variability in cash flows from the forecasted physical sale of oil or gas production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted physical sale.

Central Kansas Uplift A 180 mile-long structural expression stretching northwest to southeast through central Kansas, with our leaseholds in Graham, Rooks, Ellis, Russell, Barton, Stafford and Barber counties.

Collar A financial arrangement that effectively establishes a price range for the underlying commodity. The producer bears the risk of fluctuation between the minimum (floor) price and the maximum (ceiling) price.

Denver-Julesburg (DJ) Basin A geologic depression encompassing Eastern Colorado, Southwest Wyoming, Northwest Kansas and Western Nebraska.

Development well A well drilled into a known producing formation in a previously discovered field.

EUR Estimated ultimate recovery.

Exploratory well A well drilled into a previously untested geologic formation to test for commercial quantities of oil or gas.

Field A geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface.

Gas All references to gas in this report refer to natural gas.

Gross Gross natural gas and oil wells or gross acres equal the total number of wells or acres in which the Company has a working interest.

Hedging The use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility.

IRR Internal rate of return.

Net Net gas and oil wells or net acres are determined by summing the fractional ownership working interests the Company has in gross wells or acres.

Piceance Basin A geologic depression encompassing a 6,000 square mile area in Western Colorado encompassing portions of Garfield and Mesa counties, with portions extending northward into Rio Blanco County and south into Gunnison and Delta counties.

Productive Able to economically produce oil and/or gas.

Proved reserves Reserves that, based on geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reserves under existing economic and operating conditions.
Proved developed reserves Proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.
Reserves The estimated quantities of oil, gas and/or condensate, which is economically recoverable.
Transportation Moving gas through pipelines on a contract basis for others.
Williston Basin A geologic depression encompassing portions of North Dakota, South Dakota and Eastern Montana.
Working interest An interest that gives the owner the right to drill, produce and conduct operating activities on a property and receive a share of any production.

MEASUREMENTS

Barrel = Equal to 42 U.S. gallons.
Bbl = barrel of oil
Bcf = billion cubic feet of natural gas
Bcfe = billion cubic feet of natural gas equivalents
Btu One British thermal unit a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
MBbl = thousand barrels of oil
Mcf = thousand cubic feet of natural gas
Mcfe = thousand cubic feet of natural gas equivalents
MMBtu = million British thermal units
MMcf = million cubic feet of natural gas
MMcfe = million cubic feet of natural gas equivalents

ITEM 1A. RISK FACTORS.

Investing in our securities involves risk. In evaluating the Company, careful consideration should be given to the following risk factors, in addition to the other information included or incorporated by reference in this annual report. Each of these risk factors could materially adversely affect our business, operating results or financial condition, as well as adversely affect the value of an investment in our common stock. In addition, the "Forward-Looking Statements located in this Form 10-K, and the forward-looking statements included or incorporated by reference herein describe additional uncertainties associated with our business.

Risks Related to our Business and the Economy

We have incurred significant losses. We expect future losses and we may never become consistently profitable.

We have incurred significant losses in the past. For the years ended December 31, 2008, 2007, and 2006, we incurred net income (losses) from operations of ($14.2 million), $2.4 million and ($5.7 million), respectively. In addition, we had an accumulated deficit of $42.0 million at December 31, 2008. The fluctuations in oil and gas commodity prices are beyond our control and the mark-to-market accounting for related derivatives and the fair value accounting for oil and gas properties can have a significant non-cash impact on both earnings and retained earnings/accumulated deficit. There can be no assurance that we will be able to reach profitability on a consistent basis.

Table of Contents

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

At December 31, 2008, the principal amount of our total outstanding debt was $55.9 million. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Various limitations in our senior credit facility and 10.75% Secured Convertible Debentures may reduce our ability to incur additional indebtedness, to engage in some transactions and to capitalize on business opportunities. A significant downturn in our business of other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain beneficial transactions. The agreements governing our debt generally require us to comply with various affirmative and negative covenants including the maintenance of certain financial ratios and restrictions on incurring additional debt, entering into mergers, consolidations and sales of assets, making investments and granting liens. Our leverage may adversely affect our ability to fund future working capital, capital expenditures, future acquisitions, exploration or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

We may be unable to obtain funding on acceptable terms or at all because of the deterioration of the credit and capital markets, and oil and gas commodity prices. This may hinder or prevent us from meeting our future capital needs.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile due to a variety of factors, including significant write-offs in the financial services sector and the current weak economic conditions. As a result, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly, even more so for smaller companies like Teton. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt on similar terms or at all and reduced, or in some cases ceased, to provide adequate borrowing base funding to borrowers. In addition, lending counterparties under existing revolving credit facilities may be unwilling or unable to meet their funding obligations. Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due. Moreover, without adequate funding, we may be unable to execute our growth strategy, complete future acquisitions or development projects, or take advantage of other business opportunities, any of which could have a material adverse effect on our revenues, results of operations and future viability.

Our revenues, profitability, future growth and reserve levels depend on reasonable prices for oil and natural gas. These prices also affect the amount of our cash flow available for capital expenditures and payments on our debt, and our ability to borrow and raise additional capital. The amount we can borrow under our senior secured revolving credit facility (see Note 6 to the Consolidated Financial Statements) is subject to periodic borrowing base re-determinations based in part on changing expectations of future crude oil and natural gas prices. Lower prices may also reduce the amount of oil and gas that we can produce economically.

Among the factors that can cause fluctuations in such prices are:

- domestic and foreign supply, and perceptions of supply, of oil and natural gas;
- level of consumer demand;
- political conditions in oil and gas producing regions;

weather conditions;

world-wide economic conditions;

Table of Contents

domestic and foreign governmental regulations; and

price and availability of alternative fuels.

We periodically have hedges placed on our oil and gas production to attempt to mitigate this problem to some extent. See Item 7A Quantitative and Qualitative Disclosures About Market Risk.

Our credit facility has borrowing base restrictions, which could adversely affect our operations.

Our revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by our lenders in their sole discretion, based upon, among other things, our level of proved reserves and the projected revenues from the oil and natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Any increase in the borrowing base requires the consent of all lenders.

Upon a downward adjustment of the borrowing base, if borrowings in excess of the revised borrowing base are outstanding, we could be forced to repay our indebtedness in excess of the borrowing base under the revolving credit facility if we do not have any substantial unpledged properties to pledge as additional collateral. We may not have sufficient funds to make such repayments under our revolving credit facility.

We may be unable to fully execute our growth strategy if we encounter illiquid capital markets.

Our strategy contemplates growth through the acquisition, exploration, exploitation, development and production of oil and gas reserves while maintaining a strong balance sheet. We have historically addressed our short and long-term liquidity needs through the use of cash flow provided by operating activities, borrowing under bank credit facilities and the issuance of equity. Any limitations on our access to capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to acquire or develop accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of equity include market conditions, fees we pay underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

In addition, we are experiencing increased competition for the types of assets and businesses we have historically purchased or acquired. Increased competition for a limited pool of assets, as well as our limitations in the current capital markets, could result in our losing to other bidders more often or acquiring assets on less attractive terms. Either occurrence would limit our ability to fully execute our growth strategy. Many of our competitors may also have financial resources that are substantially greater than ours, which may adversely affect our ability to compete within the industry.

Our oil and gas production results are dependent on factors, including commodity prices and commodity price basis differentials, which are subject to various external influences that cannot be controlled.

Recent volatility in crude oil and natural gas prices has negatively affected the results of operations and cash flows of our oil and gas production business. The business is subject to external influences that cannot be controlled by us, including fluctuations in oil and natural gas prices, fluctuations in commodity price basis differentials, availability of economic supplies of natural gas, drilling successes in oil and natural gas operations, the timely receipt of necessary permits and approvals, the ability to contract for or to secure necessary drilling rigs and service contracts to drill for and develop reserves, the ability to acquire oil and gas properties, and other risks incidental to the operations of the oil and natural gas wells.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases while not hedging may result in significant fluctuations in our net income and stockholders equity.

We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the prices of oil and natural gas. We may in the future enter into additional hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected or the other party to the contract defaults on its obligations. Hedging transactions may limit the benefit we otherwise would have received from increases in the price for oil and natural gas, when the respective price goes above our hedged price.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition, or results of operations.

Our future success will depend on the success of our exploration, exploitation, development, and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control; including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop, or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical.

Acquisitions are a part of our business strategy and are subject to the risks and uncertainties of evaluating recoverable reserves and potential liabilities.

Our business strategy includes a continuing acquisition program. In addition to the leaseholds, we are seeking to acquire producing properties including the possibility of acquiring producing properties through the acquisition of an entire company. Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results.

The successful acquisition of producing and non-producing properties requires an assessment of a number of factors, many of which are inherently inexact and may prove to be inaccurate. These factors include: evaluating recoverable reserves, estimating future oil and gas prices, estimating future operating costs, estimating future development costs, estimating the costs and timing of plugging and abandonment and potential environmental and other liabilities, assessing title issues and other factors. Our assessments of potential acquisitions will not reveal all existing or potential problems, nor will such assessments permit us to become familiar enough with the properties fully to assess their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from a seller of a property for liabilities that we assume. We may be required to assume the risk of the physical condition of acquired properties in addition to the risk that the acquired properties may not perform in accordance with our expectations. As a result, some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels and in connection with these acquisitions, we may assume liabilities that were not disclosed to or known by us or that exceed our estimates.

Our acquisitions may pose integration risks and other difficulties.

Increasing our reserve base through acquisitions is an important part of our business strategy. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating acquisitions, could result in our incurring unanticipated expenses and losses.

In addition, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations.

We have limited operating control over our current production.

Approximately one half of our current revenues come through joint operating agreements under which we own partial non-operated interests in oil and natural gas properties. As we do not currently operate a portion of the production in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. Consequently, a portion of our operating results 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 our

Table of Contents

current non-operated properties, 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 non-operated projects may require us to increase our capital expenditure budget and could result in some wells becoming uneconomic.

The marketability of our production depends upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities, which are owned by third parties.

The marketability of our production depends upon the availability, operation, and capacity of gas gathering systems, pipelines and processing facilities, which are owned by third parties. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. We currently own an interest in numerous wells that are capable of producing but may be curtailed from time to time at some point in the future pending gas sales contract negotiations, as well as construction of gas gathering systems, pipelines, and processing facilities.

Seasonal weather conditions and lease stipulations can adversely affect the conduct of drilling activities on our properties.

Oil and natural gas operations can be adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and natural gas activities can only be conducted during the spring and summer months. This may limit operations in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our reserves and future net revenues may differ significantly from our estimates.

The process of estimating oil and natural gas reserves is complex. Reserve estimates are based on assumptions relating to oil and natural gas pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations and the percentage of interest owned by us in the well. The reserve estimates are prepared by external engineers who are experts in the geographic areas in which we operate. They analyze available geological, geophysical, engineering and economic data for each geographic area. The engineers make various assumptions regarding this data. The extent, quality and reliability of this data can vary. Although our reserve estimates are prepared in accordance with guidelines established by the industry and the SEC, significant changes to the reserve estimate may occur based on actual results of production, drilling, costs and pricing.

In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be significantly different. Sustained downward movements in oil and natural gas prices could result in additional future write-downs of our oil and natural gas properties.

The loss of key personnel could adversely affect our business.

We currently have key employees who serve in senior management roles. The loss of any one of these employees could severely harm our business. Although we have life insurance policies on our Chief Executive Officer, our Chief Operating Officer and our Chief Financial Officer, of which we are the beneficiary, we do not currently maintain key man insurance on the lives of any of the other key employees. Furthermore, competition for experienced personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected.

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

Under current accounting rules, we have incurred $9.6 million of non-cash interest expense for the year ended December 31, 2008, and may incur additional non-cash charges to future operations 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 may be material.

Table of Contents

Risks Relating To Our Common Stock

Our insiders beneficially own a significant portion of our stock.

As of February 25, 2009, our executive officers, directors and affiliated persons beneficially own approximately 8.49% of our common stock. As a result, our executive officers, directors and affiliated persons will have significant influence to:

- elect or defeat the election of our directors;
- amend or prevent amendment of our articles of incorporation or bylaws;
- effect or prevent a merger, sale of assets or other corporate transaction; and
- affect the outcome of any other matter submitted to the stockholders for vote.

In addition, sales of significant amounts of shares held by our directors and executive officers, or the prospect of these sales, could adversely affect the market price of our common stock. Management s stock ownership may discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of us, which in turn could reduce our stock price or prevent our stockholders from realizing a premium over our stock price.

The anti-takeover effects of provisions of our charter and by-laws and of certain provisions of Delaware corporate law, could deter, delay, or prevent an acquisition or other change in control of us and could adversely affect the price of our common stock.

Our amended certificate of incorporation, our by-laws and Delaware General Corporation Law (the DGCL) contain various provisions that could have the effect of delaying or preventing a change in control of us or our management which stockholders may consider favorable or beneficial. These provisions include the fact that we are subject to Section 203 of the DGCL. In general, Section 203 of the DGCL prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder. A business combination includes a merger, sale of 10% or more of our assets and certain other transactions resulting in a financial benefit to the stockholder. For purposes of Section 203, an interested stockholder includes any person that is:

- the owner of 15% or more of the outstanding voting stock of the corporation;
- an affiliate or associate of the corporation and was the owner of 15% or more of the outstanding voting stock of the corporation, at any time within three years immediately prior to the relevant date; and
- an affiliate or associate of the persons defined as an interested stockholder.

Any one of these provisions could discourage proxy contests and make it more difficult for our stockholders to elect directors and take other corporate actions. These provisions also could limit the price that investors might be willing to pay in the future for shares of our common stock.

The price of our common stock may fluctuate significantly, which may make it difficult for investors to resell common stock when they want to or at prices they find attractive.

The price of our common stock on the NASDAQ Capital Market, listed under the ticker symbol TEC, constantly changes. We expect that the market price of our common stock will continue to fluctuate. Our common stock price can fluctuate as a result of a variety of factors, many of which are beyond our control. These factors include, but are not limited to:

- low average daily trading volume;
- quarterly variations in operating results;
- operating results that vary from the expectations of management, securities analysts and investors;

Table of Contents

changes in expectations as to future financial performance, including financial estimates by securities analysts and investors;

developments generally affecting the oil and gas industry;

announcements by us, or other industry companies, of significant contracts, acquisitions, joint ventures, capital commitments or operational successes;

future sales of our equity or equity-linked securities; and

general domestic and international economic conditions including the availability of short- and long-term financing.

In addition, the stock market has from time to time experienced extreme volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Information required under Item 2 Properties is presented in conjunction with Item 1 Business.

ITEM 3. LEGAL PROCEEDINGS.

We are not a party to any legal proceedings.

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

No matters were submitted to a vote of our security holders during the fourth quarter of 2008.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Market Information

Our common stock is currently traded on NASDAQ Capital Market LLC, under the symbol TEC.

The following table sets forth, on a per share basis, the high and low prices for our common stock for each quarterly period from January 1, 2007 through December 31, 2008:

	High	Low
Year Ended December 31, 2008:		
First quarter	$5.20	$4.00
Second quarter	6.43	4.50
Third quarter	5.01	2.45
Fourth quarter	3.15	0.69
Year Ended December 31, 2007:		
First quarter	$5.52	$4.31
Second quarter	5.98	3.86
Third quarter	5.56	4.09
Fourth quarter	4.99	3.75

Table of Contents

Holders

As of February 25, 2009, there were approximately 159 holders of record of our common stock.

Dividends

We have not paid any dividends on our common stock since inception, and we do not anticipate the declaration or payment of any dividends at any time in the foreseeable future.

Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans at December 31, 2008:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance
Equity compensation plans approved by security holders:			
2003 Employee Stock Compensation Plan (1)	1,415,844	$ 3.55	
2005 Long Term Incentive Plan:			
Performance Share Units (2)			
Performance-vesting restricted common stock (2)			
Restricted common stock grants	319,732		4,734,108(3)

(1) The 2003 Employee Stock Compensation Plan was terminated upon the adoption of the 2005 Long Term Incentive Plan (the LTIP).

(2) Other than for the restricted common stock grants that vest generally over a three year period, our LTIP plans that were in place at January 1, 2008 were terminated at the end of 2008. The rights to all future

vesting of performance based common stock was waived by all employees and directors.

(3) Our LTIP provides for the issuance of a maximum number of shares of common stock equal to 20% of the total number of shares of common stock outstanding as of the effective date for the LTIP s first year and, for each subsequent LTIP year, (i) that number of shares equal to 10% of the total number of shares of common stock outstanding as of the first day of each respective LTIP year, plus (ii) that number of shares of common stock reserved and available for issuance but unissued during any prior plan year during the term of the LTIP; provided, however, that in no event shall the number of

shares of common stock available for issuance under the LTIP as of the beginning of any year plus the number of shares of common stock reserved for outstanding awards under the LTIP exceed 35% percent of the total number of shares of common stock outstanding at that time, based on a three-year period of grants.

Recent Issuances of Unregistered Securities

During the fourth quarter of 2008, there were no issuances of unregistered securities to unaffiliated third parties.

Table of Contents

Performance Graph

The graph below matches the cumulative five year total return of holders of Teton Energy Corporation s common stock with the cumulative total returns of the Russell 2000 index (of which, Teton is a member at December 31, 2008) and a customized peer group of twenty companies listed in footnote (1) below. The graph assumes that the value of the investment in our common stock, in the peer group and the index (including reinvestment of dividends) was $100 on December 31, 2002 and tracks it through December 31, 2008.

The twenty companies included in the peer group represent small and micro capitalization companies with similar oil and gas operations as Teton Energy Corporation with assets primarily in the U.S. The companies are as follows: Abraxas Petroleum Corporation, American Oil & Gas Inc., Aurora Oil & Gas Corporation, Credo Petroleum Corporation, Crimson Exploration, Inc., Double Eagle Petroleum Co., Edge Petroleum Corporation, GeoResources, Inc., Gasco Energy, Inc., NGAS Resources, Inc., Panhandle Oil and Gas Inc., Quest Resources Corporation, Delta Petroleum Corporation, Brigham Exploration Company, Berry Petroleum Company, Parallel Petroleum Corporation, Stone Energy Corporation, TXCO Resources, Inc., Tengasco, Inc. and The Meridian Resource Corporation.

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA.

The following selected financial data should be read in conjunction with our financial statements and the accompanying notes.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in thousands, except per share data)				
Statement of Operations Data:					
Total operating revenues	$ 28,810	$23,694	$ 4,022	$ 797	$
Net income (loss) from continuing operations	$ (14,173)	$ 2,377	$ (5,724)	$ (4,032)	$ (5,193)
Discontinued operations	$	$	$	$	$12,384
Net income (loss)	$ (14,173)	$ 2,377	$ (5,724)	$ (4,032)	$ 7,190
Basic income (loss) per share:					
Continuing operations	$ (0.67)	$ 0.14	$ (0.44)	$ (0.38)	$ (0.64)
Discontinued operations	$	$	$	$ (0.02)	$ 1.37
Net income	$ (0.67)	$ 0.14	$ (0.44)	$ (0.40)	$ 0.73
Fully diluted income (loss) per share:					
Continuing operations	$ (0.67)	$ 0.13	$ (0.44)	$ (0.38)	$ (0.64)
Discontinued operations	$	$	$	$ (0.02)	$ 1.37
Net income	$ (0.67)	$ 0.13	$ (0.44)	$ (0.40)	$ 0.73
Balance Sheet Data:					
Total assets	$126,858	$78,299	$41,244	$22,131	$17,612
Long-term debt	$ 55,900	$ 8,000	$	$	$
Total long-term liabilities	$ 57,198	$ 8,529	$ 78	$ 4	$

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ($ in thousands, except per Mcf amounts).

The following discussion and analysis of our plan of operation should be read in conjunction with the financial statements and the related notes. This management s discussion and analysis of financial condition and results of operations is intended to provide investors with an understanding of our past performance, financial condition and prospects.

Business Overview

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

As of December 31, 2008, we had estimated proved reserves of 16.9 Bcf of natural gas and 1,558 MBbl of oil, or a total of 26.2 Bcfe, with a PV-10 value of $28.2 million (see reconciliation of the PV-10 non-GAAP financial measure to the standardized measure under Reserves beginning on page 10). Of these reserves, 69% were proved developed reserves. Estimated proved reserves are 36% crude oil and 64% natural gas. At December 31, 2008, we controlled approximately 402,370 net acres, representing approximately 82% of our total net acreage position.

Current Economic Conditions and Credit Crisis

Our long term plans have been, and will continue to be, to economically grow reserves and production, primarily by:

(1) acquiring under-valued properties with reasonable risk-reward potential and by participating in, or actively conducting, drilling operations in order to further exploit our existing properties,

Table of Contents

(2) seeking high-quality exploration and development projects with potential for providing operated, long-term drilling inventories, and

(3) selectively pursuing strategic acquisitions that may expand or complement our existing operations.

However, with the recent slowdown in the national economy, tightening of the credit and equity markets and depressed oil and gas commodity prices, we have evaluated our short-term objectives and the impact of these factors on our 2009 capital and operating budgets. In light of the current economic environment and its impact on our industry, our focus for 2009 is on maintaining production of our operated properties in the Central Kansas Uplift at their fourth quarter 2008 levels 634 gross BOEPD) and participating in the Piceance Basin completions (3 scheduled) and recompletions (6 scheduled) that are planned by the operator of the property, Berry Petroleum Company. Additionally, we are being carried on the drilling of up to four Bakken wells in the Williston Basin by RTA during 2009 and will drill one Greybull well in the Big Horn Basin with our partner, Unit Petroleum Inc., which is paying 90% of the costs to casing point (we will share 50/50 in the additional costs of the well if it is determined to be successful). Refer to the heading Liquidity and Capital Resources, for further discussion on the impacts of current economic factors on our short-term strategic plans.

Significant Developments since December 31, 2007

During 2008, we continued to grow oil and gas production and reserves, through an acquisition, which added the productive area of the Central Kansas Uplift, and through participating in an active development program within our existing basins:

On April 2, 2008, we completed the purchase of reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas for approximately $53.6 million, after post closing adjustments. The effective date of the transaction was March 1, 2008. The purchase price was funded with $40.2 million of cash and borrowing capacity available under our revolving credit facility with JPMorgan Chase, $13.0 million of our common stock, or 2,746,124 common shares, and 625,000 warrants valued at $434.

On May 16, 2008, we repaid $6.6 million of the $9.0 million face value of 8% Senior Subordinated Convertible Notes that closed on May 16, 2007 (the Notes). The remaining $2.4 million was converted into 480,000 shares of our common stock at a conversion price of $5.00 per share.

On June 18, 2008, we closed on the private placement of $40 million aggregate principal amount of 10.75% Secured Convertible Debentures due on June 18, 2013 (the Debentures). The holders each had a 90-day put option, expiring September 18, 2008, whereby they elected to reduce their investment in the Debentures by a total of 25% of the face amount, or $10 million in the aggregate. We repaid the $10 million to our investors on September 18, 2008, reducing the total outstanding amount on the Debentures to $30 million. The net proceeds from the issuance of the Debentures, after fees and related expenses (and excluding the 90-day 25% put options) were approximately $28 million. These funds were used to pay down our outstanding indebtedness on our revolving credit facility.

In connection with the privately placed 10.75% Secured Convertible Debenture, the borrowing base on our $150 million revolving credit facility was reduced from $50 million to $32.5 million. On August 1, 2008 the borrowing base was re-determined and increased to $34.5 million (on November 1, 2008, the borrowing base was reaffirmed at $34.5 million). The balance outstanding at December 31, 2008 was $29,650,000.

On October 7, 2008, we and all of the investors who held the 3,600,000 warrants (issued in connection with the May 2007 financing transaction which consisted of the $9.0 million Convertible Notes and warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price for a period of five years, with a cashless exercise option) agreed to exchange the warrants for 900,000 shares of the Company s common stock. As a result, the carrying value of the current liability for the financing warrants was reduced to the fair value as of the date of the exchange and we recognized a gain of $6.9 million as a result.

On November 13, 2008, one of our investors, who held a $3.75 million investment in the 10.75% Secured Convertible Debentures, elected to convert, bringing the total outstanding amount on the Debentures to $26.25 million. We issued 576,924 shares of our Common Stock (based on the $6.50 stated conversion rate), 216,541 shares of our Common Stock related to the interest make-whole provision and paid $893,000 in cash related to accrued interest through the conversion date and for the remaining amount of the interest make-whole. The total cost to the Company was $1.7 million or $2.05 million less than the outstanding amount of the debt that was converted.

During the twelve months ended December 31, 2008, we recognized impairment expense, under SFAS No. 144, related to our non-operated properties in the Teton-Noble AMI of $11.8 million. During 2008, we received and signed AFEs for a total of 105 wells in the Teton-Noble AMI. During the fourth quarter of 2008, we notified the operator of our election to go non-consent on the remaining 2008 drilling program for two reasons: (1) we wanted time to evaluate the results of adding pumping units to existing production to bring the production volumes up to economic levels, and (2) we believe it is more prudent to retain the funds that would be expended for additional new wells in this area while we are in these times of credit and capital market constraints and lower commodity prices. Noble agreed with our approach and has informed us that they will not drill any additional wells in the Teton Noble-AMI until the production issues are resolved. The results of these wells have been disappointing for the amount of investment made to date. The gathering system problems that are being addressed by the operator are resulting in marginal economics for the project, and we intend to exercise our right to go non-consent until the volume-related problems are resolved.

Significant Developments since December 31, 2008

On January 16, 2009, we retired an additional $750 of the 10.75% Secured Covertible Debentures for $273, bringing the total outstanding on the Debentures to $25.5 million.

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Table of Contents

Results of Operations

	Year Ended December 31,			Percent Change Between	
	2008	2007	2006	2007 to 2008	2006 to 2007
	(revenues and expenses in thousands)				
Net production volumes					
Oil (Bbl)	192,437	16,575		1061%	nm
Gas (Mcf)	1,657,728	1,127,568	737,175	47%	53%
Total (Mcfe)	2,812,350	1,227,021	737,175	129%	66%
Realized price pre hedging					
Oil (per Bbl)	$ 95.27	$ 76.32	$ 0.00	25%	nm
Gas (per Mcf)	$ 6.11	$ 4.42	$ 5.46	38%	-19%
Total (per Mcfe)	$ 10.12	$ 5.10	$ 5.46	98%	-7%
Realized price net of hedging					
Oil (per Bbl)	$ 92.03	$ 74.81	$ 0.00	23%	nm
Gas (per Mcf)	$ 7.30	$ 5.49	$ 5.46	33%	1%
Total (per Mcfe)	$ 10.60	$ 6.06	$ 5.46	75%	11%
Oil and gas sales					
Oil sales	$ 18,334	$ 1,265	$	1349%	nm
Gas sales	10,135	4,988	4,022	103%	24%
Total	$ 28,469	$ 6,253	$ 4,022	355%	55%
Oil and gas operating expenses					
Lease operating expense	$ 4,481	$ 705	$ 325	536%	117%
Transportation expense	1,827	652	493	180%	32%
Production taxes	1,932	412	251	369%	64%
Total	$ 8,240	$ 1,769	$ 1,069	366%	65%
Data on a per Mcfe basis					
Realized price net of hedging	$ 10.60	$ 6.06	$ 5.46	75%	11%
Lease operating expense	1.59	0.57	0.44	180%	30%
Transportation expense	0.65	0.53	0.67	23%	-21%
Production taxes	0.69	0.34	0.34	102%	0%
Total production costs	2.93	1.44	1.45	103%	-1%
Gross margin	$ 7.67	$ 4.62	$ 4.01	66%	15%

Gross margin percentage	72%	76%	73%		
General and administrative					
Stock-based compensation, net of exploration reclass	$ 3,192	$ 3,288	$ 2,928	-3%	12%
Other compensation	2,772	2,175	2,086	27%	4%
Professional fees	1,904	2,373	967	-20%	145%
Other general and administrative	1,720	1,145	1,167	50%	-2%
Total general and administrative	$ 9,588	$ 8,981	$ 7,148	7%	26%
Other operating expenses					
Exploration expense	$ 4,831	$ 1,847	$ 448	162%	312%
DD&A oil and gas	$ 14,396	$ 3,751	$ 1,697	284%	121%
DD&A other	$ 229	$ 81	$ 52	183%	56%
Other income (expense)					
Realized gain hedging	$ 1,349	$ 1,181	$	14%	nm
Unrealized gain (loss) hedging	12,662	(857)	403	1577%	-313%
Gain (loss) on derivative contracts	7,762	(2,624)		396%	nm
Interest (expense) income, net	(11,976)	(2,588)	265	363%	-1077%
Interest make-whole premium on debt conversion	(1,236)			nm	nm
Total	$ 8,561	$ (4,888)	$ 668	-275%	-832%

31

Table of Contents

Results of Operations 2008 Compared to 2007

We had a net loss from continuing operations for the year ended December 31, 2008 of $14.2 million compared to net income of $2.4 million for 2007. Factors contributing to the $16.6 million decrease in net income from 2007 to 2008 included the following:

During 2007, we sold half of our 25% working interest in the Piceance Basin non-operated properties for $36.7 million in cash, including purchase price adjustments, and oil and gas properties and related production valued at $4.7 million, for a gain on sale of assets totaling $17.4 million.

Oil and gas production net to our interest in 2008 was 2.8 Bcfe resulting in $28.5 million in oil and gas sales, at an average wellhead price of $10.12 per Mcfe for the year. In 2007 our net production was 1.2 Bcfe resulting in $6.3 million in oil and gas sales, at an average wellhead price of $5.10. The 129% increase in production volumes resulted from additional wells being put on line in 2008 and the acquisition of the Central Kansas Uplift properties in April 2008 (largely crude oil production being converted from barrels to Mcfe at the rate of 6 Mcfe per barrel of oil). The higher 2008 average price per Mcfe resulted from an average oil price of $95.27 per barrel and an average gas price of $6.11 per Mcf. Since the traditional conversion factor of 1:6 for barrels to Mcfe is used for volumes, it impacts the average price per Mcfe significantly, weighting it higher in 2008 due to the higher oil prices (i.e., our oil prices averaged 15.6x the price of natural gas per Mcfe, much higher than the 6x conversion factor for volumes). Additionally, Rocky Mountain natural gas traded at a higher than normal discount to natural gas in the rest of the country during parts of 2007 due to pipeline capacity constraints limiting the ability to move gas that was produced in the Rocky Mountain region into other areas of the country. Throughout the country, higher levels of natural gas in storage, related to additional new production volumes and lower than average winter temperatures in some parts of the country, caused the price of natural gas to decrease in the last quarter of 2008. That trend has continued into early 2009 and we believe it may continue for the foreseeable future.

The price of crude peaked at over $145 per barrel in 2008 but retreated to around $44 at December 31, 2008. To protect our cash flows from these severe changes in prices, we contract from time to time for fixed price swaps or for costless collar hedges (see full discussion under Contractual Obligations below). However, the realized gains (losses) on our oil and gas derivative contracts are presented under Other Income (Expenses) in the Consolidated Statement of Operations, so the fluctuations in commodity prices do appear in the Oil and Gas Sales line.

Our lease operating expenses, transportation costs and production taxes for 2008 increased to $4.5 million (536% over 2007), $1.8 million (180% over 2007) and $1.9 million (369% over 2007), respectively, all due largely to the 355% increase in oil and gas sales in 2008 compared to 2007. Lease operating expense increased by an additional 51% over the increase in production resulting from the fact that the new production in the Central Kansas Uplift is largely crude oil and that cost of operations related to crude oil, on a per-Mcfe basis, is higher than natural gas, which had made up over 90% of our production prior to the acquisition in Kansas.

General and administrative expenses increased from $9.0 million ($5.7 million cash and $3.3 million non-cash) for the year ended December 31, 2007 to $9.6 million ($6.4 million cash and $3.2 million non-cash) for the year ended December 31, 2008, due to:

- a net increase in compensation expense of approximately $400 from staffing increases throughout the year for the significant increase in operations in 2008, split as approximately $530 of cash compensation in the form of salaries (no bonuses were accrued, or to be paid, for 2008) and a decrease of approximately $130 of non-cash compensation;

- an increase in office supplies and rent expense for the larger number of staff of approximately $624; and

- an increase in Board of Directors cash compensation of approximately $177 (the Board members have permanently waived their rights to 93,000 shares of common stock that was earned in 2008);

- all offset somewhat by $133 savings in public company compliance costs related to efficiencies implemented throughout 2008 and various other smaller items.

Although $3.8 million of stock compensation expense related to the 2006 LTIP plan had been earned by contract at December 31, 2008, our employees, officers and directors chose to permanently waive their rights to that stock compensation. Additionally, the 2007 LTIP plan is expected to achieve 100% of its target goals by its plan year end at June 30, 2009, but, since the officers and directors involved in that plan have also waived their rights to that stock compensation that would be payable in 2009, no accrual has been made, and no payout is anticipated at June 30, 2009. General and administrative expenses for 2009 are estimated at a much lower level of approximately $5.1 million ($4.7 million of cash and $.4 million of non-cash). As long as the current economic crisis exists, we have no intention of paying bonuses, raising existing salaries or hiring new positions within the Company. The 2006 and 2007 LTIP programs, beginning with the awards that were scheduled to vest at December 31, 2008, have all been terminated, and the rights to any vesting of the related stock awards have been permanently waived by employees, officers and directors. Additionally, all general and administrative costs continue to be thoroughly scrutinized, with only the most essential needs remaining in the budget. This results in approximately a 47% reduction in expected G&A expense in 2009 when compared to the actual expenses of $9.6 million in 2008.

Exploration expense for 2008 of $4.8 million relates largely to delay rentals, geological and geophysical expenses incurred by us in the CKU ($.1 million) and eastern DJ ($.3 million), expired leases in the CKU ($3.3 million) and Washco ($0.1 million) and the costs of the geosciences staff needed to execute on our drilling program in Kansas. We use 3D seismic studies to locate potential drilling sites in each basin.

Depletion and depreciation expense increased from $3.8 million in 2007 to $14.6 million in 2008 due to the 129% increase in production volumes in 2008 compared to 2007, development drilling in the DJ Basin during 2008 that resulted in small incremental reserve additions and pricing revisions at December 31, 2008 which resulted in lower reserves overall than would have been expected under better pricing scenarios. December 31, 2007 reserves were estimated based on pricing of $82.50 per barrel of oil and $6.04 per Mcf of gas, while December 31, 2008 reserves are estimated on $41.00 per barrel of oil and $4.61 per Mcf of gas. Thus, there were negative pricing revisions to the reserves of each of our operating areas at year end 2008. The result is a larger Developed Property pool, due largely to development drilling and acquisitions, to deplete over a smaller reserve pool, due largely to lower prices and poorer than expected drilling results in the Teton-Noble AMI.

We also recognized $14.3 million of impairment expense related to the DJ Basin assets, mostly in the Teton-Noble AMI. The currently lower than expected production from the Teton-Noble AMI wells has resulted in lower reserve estimates being assigned to the wells. In the fourth quarter of 2008, we notified the operator of our intent to go non-consent on the remaining 2008 drilling program for two reasons: (1) we wanted time to evaluate the results of adding pumping units to existing production to bring the production volumes up to economic levels, and (2) we believe it is more prudent to retain the funds which would be expended for additional new wells in this area while we are in these uncertain times of credit and capital market constraints and lower commodity prices. Noble agreed with our approach and drilled no additional wells in 2008. The results of these wells have been disappointing for the amount of investment made to date. The gathering system problems and disappointing production volumes that are being address by the operator are resulting in marginal economics for the project, and we intend to exercise our right to go non-consent until the problems are resolved.

Our realized gain on oil and gas derivative contracts increased from $1.2 million in 2007 to $1.3 million in 2008. When we purchased the CKU properties in April 2008, we entered into crude oil costless collar contracts through April 2013 to lock in the economics of the acquisition. In the early months after the transaction, the price of crude oil soared to over $145 per barrel, while our hedging contracts contained price ceilings of $103. Thus, we recognized losses of approximately $3 million through the end of the third quarter 2008. Since then, the price of crude oil has decreased significantly, resulting in approximately $1.7 million of realized gain on crude oil sales in the fourth quarter 2008. We have crude oil costless collar contracts in place through April 2013 for 100% of our December 31, 2008 production volume, adjusting monthly to coincide with the production curve of the current wells, at a floor price of $90 per barrel and a ceiling price of $104 per barrel. Additionally, since we are pursuing the possible sale of the Piceance assets, we sold our CIG natural gas collars in November 2008 for a gain of $243 and our NYMEX natural gas collars in December 2008 for a gain of $1.8 million. Prior to the sale of our natural gas hedges, we recognized a gain of approximately $550 on natural gas sales during the fourth quarter.

During 2008 we recognized an unrealized derivative gain of $12.7 million, compared to an unrealized loss of $857,000 in 2007, related largely to the precipitous drop in the price of crude oil during the last half of 2008 The gain represents marking the contracts to market at December 31, 2008, based on the future expected prices of the related commodities. Actual results from the contracts will be booked as realized gains (losses) as the production volumes being hedged are actually produced.

Interest expense, net ($12.0 million) in 2008 includes interest charged on the senior bank facility, the 8% senior subordinated convertible notes that were converted or repaid in May 2008 and the 10.75% secured convertible debentures, and the amortization of debt issuance discount and debt issuance costs. Approximately $3.5 million was actual interest expense on outstanding debt and approximately $9.3 million was amortization related largely to the 8% secured convertible notes. The line item Interest make-whole premium on conversion of debt in the Consolidated Statement of Operations relates to the interest make-whole and unamortized original issue discount related to $3.75 million of the 10.75% Convertible Debt that was converted in November 2008. Although $1,236 is recognized as expense in accordance with current accounting authoritative literature, we converted $3.75 million of outstanding debt for a total cost to the Company of $1.7 million. Thus, a related gain on the transaction of $2.05 million was accounted for by crediting the equity section of the balance sheet.

Results of Operations 2007 Compared to 2006

We had net income from continuing operations for the year ended December 31, 2007 of $2.4 million compared to a net loss of $5.7 million for the same period in 2006. Factors contributing to the $8.1 million increase in net income from 2006 to 2007 included the following:

We sold half of our 25% working interest in the Piceance Basin non-operated properties for $36.7 million in cash, including purchase price adjustments, and oil and gas properties and related production valued at $4.7 million, for a gain on sale of assets totaling $17.4 million.

Oil and gas production net to our interest in 2007 was 1.2 Bcfe resulting in $6.3 million in oil and gas sales, at an average wellhead price of $5.10 per Mcfe for the year. In 2006 our net production was 737 MMcfe resulting in $4.0 million in oil and gas sales, at an average wellhead price of $5.46. The 63% increase in production volumes resulted from additional wells being put on line in 2007. The lower 2007 average price per Mcfe resulted from prices in 2006 being higher than normal due largely to the severity of the hurricane season in late 2005; the effects of which lasted into the first half of 2006. Additionally, Rocky Mountain natural gas traded at a higher than normal discount to natural gas in the rest of the country during parts of 2007 due to pipeline capacity constraints limiting the ability to move gas that was produced in the Rocky Mountain region into other areas of the country. The completion of the Rocky Mountain Express Pipeline (REX), which is ultimately projected to move up to 1.8 Bcfd of natural gas out of the Rocky Mountain region, is expected to help alleviate the capacity constraints. The first sections of REX began operation in early 2007, and the final completion is scheduled for 2009.

Our lease operating expenses, transportation costs and production taxes for 2007 increased to $705 (117% over 2006), $652 (32% over 2006) and $412 (64% over 2006), respectively, due largely to the 55% increase in oil and gas sales in 2007 compared to 2006. Lease operating expense increased by an additional 54% over the increase in production resulting from the fact that the new production in each of the Piceance, DJ and Williston Basins caused some operating inefficiencies while the outside operators were learning the best approaches to operating in new locations, and due to severe weather in early 2007 resulting in some additional lease operating expenses. As the outside operators are adding more wells and becoming more familiar with the operating areas, the lease operating expenses are beginning to decrease from the higher levels associated with new producing areas.

General and administrative expenses increased from $7.1 million for the year ended December 31, 2006 to $9.0 million for the year ended December 31, 2007, due largely to:

- a net increase in compensation expense of approximately $1.2 million due to approximately $550 of non-cash compensation expense increase from stock-based grants as a result of meeting performance milestones associated with our long-term incentive plan and an increase in salaries of approximately $620;

- a net increase of approximately $800 in consulting and related expenses associated with SOX compliance, oil and gas accounting services, investor relations, compensation benchmarking reports and study, and financial and legal services related to acquisitions, financings and the divestiture of part of the Piceance properties.

Exploration expenses for 2007 of $1.8 million relate largely to delay rentals, geological and geophysical expenses incurred by us in the eastern DJ and Williston Basins and the reclassification of general and administrative expense noted directly above. We use 3D seismic studies to locate potential drilling sites in each basin.

Depletion and depreciation expense increased from $1.7 million in 2006 to $3.8 million in 2007 due to the higher gas production volumes in 2007 compared to 2006.

Table of Contents

During 2007 we recognized an unrealized derivative loss of $857 related to derivative contracts (natural gas and crude oil fixed price swaps). The loss represents marking the contracts to market at December 31, 2007, based on the future expected prices of the related commodities. Actual results from the contracts will be booked as realized gains (losses) as the production volumes being hedged are actually produced.

Interest income ($425) and interest expense ($3.0 million) in 2007 include interest income from the cash balances maintained and interest expense on our line of credit combined with amortization of deferred debt issuance costs. We maintained higher cash balances late in 2007 resulting from the partial sale of interest in the Piceance property.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash provided by debt and equity offerings and borrowings under our bank credit facility. In the past, these sources have been sufficient to meet our business needs. Recent adverse developments in financial and credit markets have made it very difficult and much more expensive to access capital markets. Although the credit markets tightened in the latter half of 2008, we believe that the amounts available to us under our existing $150 million credit facility ($34.5 million borrowing base at December 31, 2008), together with the anticipated net cash provided by operating activities during 2009 and proceeds from potential sales of non-operated properties, will provide us with sufficient funds to develop a limited amount of new reserves, maintain our current facilities, complete our limited capital expenditure program, and meet our debt obligations through 2009.

In response to the lower commodity prices and continued constrained capital markets, the capital expenditure budget for 2009 will focus primarily on the maintenance of production levels for our operated properties in the Central Kansas Uplift (refer to discussion below under the heading Cash Flows and Capital Expenditures), completion of a limited number of wells drilled in 2008 that were not completed by year end (Piceance and Williston), and lease and seismic costs.

Depending on the timing and amounts of our capital projects and future developments in the capital markets, we may be required to seek additional sources of capital. While we would normally believe that we would be able to secure additional financing if required, we can provide no assurance that we would be able to do so or as to the terms of any additional financing. Due to the uncertain state of the current capital markets, securing additional financing would likely be much more difficult than it has been in the past, and, if secured, the terms would likely be more onerous. While we have publicly stated our plans to sell non-operated properties as part of our current strategic plan, in response to this situation, we are increasing our emphasis on the sale of our non-operated assets in the Piceance and DJ Basins in order to raise additional funds as may be necessary. This may also interact with our capital budget for 2009 by reducing it for the amounts expected to be spent in those basins.

Future developments in the capital markets are expected to include the reduction of lenders pricing decks (i.e., the commodity prices upon which lenders base their determinations of borrowing bases), which could lead to lowering of the Company s borrowing base. With the significant declines in commodity prices since the summer of 2008, it is likely that there will be a reduction of the price decks by the banks which are included in the our revolving credit facility, and a consequent reduction of our borrowing base at the next redetermination, scheduled for May 1, 2009. If the borrowing base is lowered below the then-outstanding balance, which would likely be the results of a redetermination based on lower commodity prices, any excess over the re-determined borrowing base (a borrowing base deficiency) would be required to be repaid in three equal installments on the last day of each month following the redetermination. The sale of non-operated properties, the liquidation of our oil hedges or an equity infusion would be possible sources of funds used to repay any borrowing base deficiency. Due to the uncertain state of the current capital markets and the oil and gas industry, there is no assurance that we would be able to complete any of these undertakings successfully. We do not regard the liquidations of our hedges as an ideal interim strategy as these hedges provide protection against the lowering of the borrowing base. For every dollar that the price of oil declines, our hedge value increases by one dollar. While we have not hedged our gas production, we believe the sale of our natural gas properties would provide protection against declining prices in natural gas.

Table of Contents

The credit facility also contains two financial covenants with which we are required to comply quarterly:

1. Ratio of total debt to EBITDAX (as defined in the credit facility agreement): We will not, as of the last day of the fiscal quarter, permit our ratio of total debt as of the end of such fiscal quarter to EBITDAX for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding the date of determination for which financial statements are available to be greater than 3.5 to 1.0.

2. Current ratio: We will not, as of the last day of any fiscal quarter, permit our ratio of (i) consolidated current assets (including the unused amount of the total commitments under the credit facility, but excluding non-cash assets under SFAS 133) to (ii) consolidated current liabilities (excluding non-cash obligations, SFAS 133 liabilities and current maturities under or with respect to the credit facility, the convertible debt or any other senior subordinated debt, whether such amounts are reflected as a liability under GAAP or not) to be less than 1.0 to 1.0.

There exists an intercreditor agreement between the holders of the 10.75% Convertible Debentures and the banks in the credit facility whereby the same financial covenants apply to the Convertible Debentures.

As of December 31, 2008, we were in compliance with all financial and non-financial covenants of our debt agreements. However, the lower commodity prices being experienced, coupled with a reduced capital spending budget during this time of tight capital markets, will result in EBITDAX being lower in the upcoming months. Lower EBITDAX may require us to lower our debt outstanding to be able to maintain compliance with the total debt to EBITDAX ratio requirement. The sale of non-operated properties, the liquidation of our oil hedges or an equity infusion would be possible sources of funds used to lower our outstanding total debt. Due to the uncertain state of the current capital markets and the oil and gas industry, there is no assurance that we would be able to complete any of these undertakings successfully. We do not regard the liquidations of our hedges as an ideal interim strategy as these hedges provide protection against the lowering of the borrowing base. For every dollar that the price of oil declines, our hedge value increases by one dollar, and for every dollar a falling oil price decreases EBITDAX, the oil hedges will increase EBITDAX by one dollar for the hedged volumes. We expect our oil hedges to cover 99% of our volumes of existing wells production in 2009, with production from new wells drilled being the only volumes sensitive to actual pricing of crude oil. Additionally, the potential sales noted above of the Piceance and DJ Basin assets would supply funds to lower the outstanding debt and improve the debt/EBITDAX ratio.

Our operating cash flows may also fluctuate throughout the year due to weather, changes in prices and volumes, as well as the timely collection of receivables. The availability of oil field services and supplies such as concrete, pipe and compression equipment are expected to have a significant influence on our capital budget and net cash provided by operating activities. Our future growth is further dependent upon the success and timing of our exploration and production activities, new project development, efficient operation of our facilities and our ability to obtain financing at acceptable terms.

As of December 31, 2008, we have approximately 99% of our total oil production hedged at a ceiling price of $104.00 and a floor price of $90.00 per barrel, and that 99% ratio is expected to continue throughout 2009 for the currently existing wells and for the nine scheduled recompletions. Our hedges are transacted with JPMorgan Ventures Energy Corporation and are currently in place through April of 2013. At December 31, 2008, the liquidation value of our oil hedges was $12.9 million. Refer to section entitled Contractual Obligations below for further discussion.

Additionally, 100% of our operated production is purchased by credit worthy third parties. However, management believes that in the absence of these third parties sufficient resources exist to bring this production to market. During the year-ended December 31, 2008, revenues from our operated properties accounted for 65.8% of total revenues. This percentage is expected to increase during 2009 as our principal operated area of the Central Kansas Uplift was acquired during 2008 and we began accounting for our share of revenues from the area on April 1, 2008. Our 2009 capital program is expected to focus primarily on the maintenance of current production levels for our operated CKU properties.

We rely on the operator to market our share of production from our non-operated properties. Timely collection of receivables depends in large part on the credit worthiness of our operators. We believe that the operators, Berry Petroleum Company, Noble Energy Inc. and Evertson Operating Company, are credit worthy operators.

Table of Contents

In the past we have also received proceeds from the exercise of outstanding warrants and/or options. However, based on the current price of our common stock compared to the exercise price of the outstanding warrants ($3.24, $6.00 and $6.06 for all outstanding warrants) and options ($3.11 - $3.71 per share) and the current economic environment, we do not anticipate receiving such proceeds during 2009. During the years ended December 31, 2008, 2007 and 2006, we received warrant and option proceeds of $1,914, $3 and $6,234, respectively. At December 31, 2008, warrants to purchase 1,272,451 shares of common stock were outstanding. These warrants have a weighted average exercise price of $5.51 per share and expire between April 2010 and December 2012. At December 31, 2008, options to purchase 1,415,844 shares of common stock were outstanding. These options have a weighted average exercise price of $3.55 per share and expire between April 2013 and May 2015.

Cash Flows, Capital Expenditures and Other Cash Requirements

Our capital budget for 2009 is currently estimated at $10.5 million and focuses largely on maintenance of production and reserves in our operated properties in the Central Kansas Uplift with a planned 33 wells in the AMI in which we have an approximate 60% working interest. Additionally we will pay our share (12.5% working interest) of the completion costs of three of the 20 wells in the Piceance which were drilled in 2008 and not completed by December 31, 2008, as well as six recompletions in the Piceance Basin. The completions of the additional 17 wells that were drilled in 2008 are not expected to occur until 2010. Drilling in the Central Kansas Uplift is expected to begin around mid-year 2009, and the completions in the non-operated Piceance Basin are expected to occur late in the second quarter or in the third quarter of 2009. The operator has informed us that no new drilling is currently planned for the Piceance Basin in 2009. Additional costs included in the 2009 capital expenditure budget include our share of drilling the first Big Horn well (90% carried to casing point by Unit Petroleum Company) and leasehold and seismic costs necessary to maintain our future operations. The permit for the first Big Horn well was obtained on December 29, 2009, and is subject to winter and wildlife drilling stipulations. Thus, the well is planned for the last half of 2009. Refer to discussion above under the heading Liquidity and Capital Resources, regarding anticipated sources and availability of financing.

During the latter half of 2008, we notified the operator of our intent to go non-consent in the Teton-Noble AMI in order to: 1) have more time to evaluate the results of adding pumping units to existing production to bring the production volumes up to economic levels, and 2) retain the funds that would have been expended for additional new wells in the area due to the capital market constraints and lower commodity prices. The operator agreed with our position and notified us that it does not intend to drill a significant number of new wells in 2009. We will not participate in any new wells until the problems are resolved to our satisfaction.

On November 13, 2008 we and our partners spud the Viall #30-1 well in our Goliath project in the Williston Basin to test the Stonewall, Red River and Winnipeg formations, and the drilling rig was released on December 16, 2008 and moved off location on December 22, 2008. Completion operations commenced on January 5, 2009. As of February 25, 2009, testing of the Winnipeg formation did not indicate commercially viable production from that formation, but the Red River C and D formations tested positive for commercially viable reserves. The well is waiting on pipeline connection to a gas processing facility.

The first of four locations in the Bakken Shale play, subject to a participation agreement with Red Technology Alliance LLC (RTA) on Teton s 88,472 gross acreage block, was originally expected to be spud in the first quarter of 2009. RTA has notified us that they intend to renegotiate the terms of the existing agreement due to low commodity prices. In accordance with the participation agreement, RTA will carry us on up to four wells, at their election, in order to earn up to a 40-percent working interest in the project, which would change our working interest from 25% to 15%.

Our primary capital needs for the three years ended December 31, 2008, 2007 and 2006 were:

	As of December 31,		
	2008	2007	2006
Property acquisition costs	$ 40,827	$ 6,807	$ 3,323
Exploration	3,113	2,712	1,823
Development	30,826	32,900	17,163

Total	$ 74,766	$ 42,419	$ 22,309

Other Cash Requirements

In June 2008, we issued $40 million in 10.75% Secured Convertible Debentures due in 2013 with a conversion price of $6.50. The investors elected to exercise the option to put 25% of the investment back to us in September, reducing the outstanding principal balance to $30 million. There are no additional put options available to the investors for this issuance. The Debentures include a three-year interest make-whole provision whereby, if either the investors elect to convert or we elect to repay the Debentures before the three-year anniversary of the original issuance date, the investors are entitled to receive an amount equal to the present value of the interest payments that would have been received through the three-year anniversary. Within certain pricing constraints, we have the option to pay all, or part, of the interest make-whole in shares of our common stock. During the fourth quarter of 2008, one of our investors, who held a principal balance, after the September put, of $3.75 million, elected to convert its Debentures to common stock. We issued 576,924 shares of our common stock (based on the $6.50 conversion rate), 216,541 shares of our common stock related to the interest make-whole provision and paid $893,000 in cash related to accrued interest through the conversion date and for the remaining amount of the interest make-whole. The price of our common stock on the date of the holder optional redemption was $1.44. Thus, we retired the $3.75 million of debentures for a total value of approximately $1.7 million. The difference is included in our Additional Paid in Capital line item in the equity section of our balance sheet. Subsequent to December 31, 2008, we retired an additional $750 of the notes for $273, bringing the current balance outstanding to $25.5 million.

At December 31, 2008 the outstanding principal balance on our Debentures was $26,250,000. Interest is payable semi-annually on each of January 1st and July 1st. We paid approximately $1.4 million of interest on January 1, 2009, and we believe that the amounts available to us under our existing credit facility, the anticipated net cash provided by operating activities during 2009 and proceeds from potential sales of non-operated properties will provide us with sufficient cash flow to meet our interest payment on July 1, 2009, which is again expected to be approximately $1.4 million. If our investors elect to convert their debentures during 2009, we may be required to seek additional sources of funding or to reallocate our existing cash flows to meet our obligations. The maximum remaining make whole interest is approximately $6.4 million after giving effect to the $750 reduction which occurred in January 2009.

Operating Activities

During the year ended December 31, 2008, net cash provided by operating activities was $9,094, an increase of $11,162 over net cash used in operating activities during the year ended December 31, 2007 of $(2,068). Our net loss of $14.2 million for 2008, a decrease of $16.6 million over the prior year net income of $2.4 million, was adjusted for non-cash items to arrive at the net cash used in operating activities. This increase in net loss is due largely to the impairment expense, a non-cash item required by SFAS No. 144 when the sum of the future undiscounted net revenues (PV10) is less than the properties recorded book value, recognized on our non-operated properties in the Teton-Noble AMI of approximately $11,880 and our operated DJ Basin assets (Washco and Frenchman Creek) of $2,380, an increase in the realized gain on oil and gas derivative contracts of $168, an increase in general and administrative expenses of $607 (see detailed G&A discussion above under Results of Operations 2008 Compared to 2007)), an increase in interest expense related to our borrowings under our revolving credit facility of $1,265 and our Debentures of $1,949 and $1,028 related to the interest make-whole premium on the conversion of $3.75 million face amount of our Debentures and an increase in non-cash interest expense related to the amortization of deferred debt discount and issuance costs of $9,263 related to the remaining amortization on the 8% Convertible Notes issued in 2007 as well as amortization of costs incurred in 2008 related to the issuance of the 10.75% Secured Convertible Debentures. The non-cash depreciation, depletion and accretion increased by $10.8 million due the addition of our operated properties in the Central Kansas Uplift, acquired on April 2, 2008 and to the addition of approximately 38.87 new net wells drilled in 2008. These additions resulted in a larger base to deplete, this coupled with more production and lower reserves in our non-operated areas led to the increase in non-cash depreciation, depletion and accretion expense. During 2007, we recognized approximately a $17.4 million gain on the sale of a partial interest in our Piceance properties. During 2008, our unrealized gain, a non-cash item required under SFAS No. 133 increased to $12,662, from a prior year unrealized loss of $857, and our oil and gas sales increased $22,216, due largely to the addition of our operated properties in the Central Kansas Uplift, which accounted for $14,717 of total oil and gas sales and due to an increase in the productive well count in our non-operated properties in the Piceance and Teton-Noble

AMI. Our oil and gas sales also increased, to a lesser extent, due to the fact that we recognized our first production related to our interests in the Washco area and Williston Basin late in 2007, and, as such, 2008 was the first full year of sales from those properties. The $1.6 million decrease in cash provided by net changes in working capital items (mainly due to accrued liabilities increasing during 2008 due largely to the addition of our operated properties in the Central Kansas, increased drilling activity and lower accrued payroll at year end 2008 than 2007, somewhat offset by the increases in trade accounts receivable resulting from increased sales) are largely due to the growth of the operations and drilling activities of the Company experienced during 2008.

During the year ended December 31, 2007, we used $2.1 million of net cash for operating activities, an increase of $289,000 over 2006. Our net income of $2.4 million for 2007 was adjusted for non-cash items to arrive at the net cash used in operating activities. The non-cash depreciation, depletion and accretion increased by $2.1 million due to the addition of approximately 22 new wells drilled in 2007, resulting in a larger base to deplete and more production. We had $4.8 million of non-cash debt issuance costs and debt discount amortization, as well as non-cash loss on derivative contract liabilities related to our issuance of 8% Convertible Notes, all related to debt activity in 2007. Our non-cash employee stock based compensation and stock issued for outside services remained relatively level from year to year, largely because non-cash employee stock based compensation was reduced by withholding taxes of approximately $700,000. During 2007, we recognized a $17.4 million gain on the sale of a partial interest in our Piceance properties, which reduced our interest in the area from 25% to 12.5%. This gain is an adjustment to net income to arrive at net cash used in operating activities because it is the result of an investing activity with the proceeds from the transaction being shown in that section of the Consolidated Statement of Cash Flows. The $1.0 million increase in cash provided by net changes in working capital items (mainly due to accrued liabilities increasing during 2007 due largely to increased drilling activity, somewhat offset by the increases in trade accounts receivable resulting from increased sales) are largely due to the growth of our operations experienced during 2007.

Investing Activities

During the year ended December 31, 2008, net cash used in investing activities was $77,894 as compared to $599 during 2007. During the year ended December 31, 2007, we received cash proceeds of $35.1 million in connection with the sale of oil and gas properties, $34.9 million of which was related to our sale of one-half of our Piceance assets (net of transaction costs and amounts in accounts receivable at December 31, 2007). During the same period we spent $35.6 million related to our drilling and completion programs in the Piceance, Williston and DJ Basins. Cash expenditures during 2008 related largely to the acquisition, and subsequent development, of producing properties and undeveloped acreage in the Central Kansas Uplift, as well as the development of our non-operated properties in the Piceance Basin and Teton-Noble AMI. Amounts were funded primarily from borrowings on our Amended Credit Facility, the issuance of our 10.75% Secured Convertible Debentures and cash flow from operating activities.

Financing Activities

During the year ended December 31, 2008, net cash provided by financing activities was $44,184 as compared to $22,958 during the same prior year period. We raised $30 million, net of the investors exercise of their $10 million put option, through the issuance of our privately placed 10.75% Secured Convertible Debentures (as noted above under *Other Cash Requirements*, $3.75 million was converted in the fourth quarter), and borrowed a net $21.7 million under our Amended Credit Facility. We repaid approximately $6.6 million of the $9.0 million in Senior Secured Convertible Notes issued in 2007 (the remaining $2.4 million converted to shares of our Common Stock prior to maturity). In addition, during 2008, holders exercised 599 warrants to purchase an equivalent number of common shares for proceeds of $1.9 million.

During the year ended December 31, 2007, we raised $9.0 million through the issuance of 8% senior subordinated Convertible Notes and borrowed $8.0 million under our $50.0 million credit facility. We paid $950,000 in debt issuance costs associated with these borrowings. On July 25, 2007, we completed a registered direct offering of 964,060 shares of common stock, at a price of $5.05 per share, to a selected group of institutional investors for gross proceeds of $4.9 million and paid $368,000 in offering costs. In addition, during 2007, holders of 672,701 stock options and 1,500 warrants exercised to purchase an equivalent number of common shares for proceeds of $2.4 million.

Table of Contents

Contractual Obligations

We have a Company hedging policy in place, to protect a portion of our production against future pricing fluctuations. Our outstanding hedges as of December 31, 2008, all of which are with JPMorgan Ventures Energy Corporation, are summarized below:

Type of Contract	Remaining Volume	Fixed Price per Barrel	Price Index (1)	Remaining Period
Oil Costless Collar	143,545	$90.00 Floor/$104.00 Ceiling	WTI	01/01/09-12/31/09
Oil Costless Collar	106,876	$90.00 Floor/$104.00 Ceiling	WTI	01/01/10-12/31/10
Oil Costless Collar	87,920	$90.00 Floor/$104.00 Ceiling	WTI	01/01/11-12/31/11
Oil Costless Collar	79,611	$90.00 Floor/$104.00 Ceiling	WTI	01/01/12-12/31/12
Oil Costless Collar	25,192	$90.00 Floor/$104.00 Ceiling	WTI	01/01/13-04/30/13
Total Bbl	443,144			

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

The costless collar hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements to a fixed point. Consequently, while these hedges are designed to decrease our exposure to price decreases while allowing us to share in some upside potential of price increases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the oil contracts listed above, a $1.00 hypothetical change in the WTI price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the unrealized gain or loss on hedging activities in 2008 of $443. The Company plans to continue to evaluate the possibility of entering into additional derivative contracts, as prices change and additional volumes become available in the future, to further decrease exposure to commodity price volatility.

At December 31, 2008, approximately 99% of our total crude oil production is hedged at a floor price of $90 per barrel through April 2013. It is our intent to continue to maintain these hedge contracts throughout the course of their lives, but they could be liquidated if the Company found itself in need of cash that could not be raised otherwise. At today s prices the contracts are in-the-money and have a liquidation value of approximately $12.9 million at December 31, 2008. This amount varies as the future price of crude oil varies from day to day. At December 31, 2008, we have no natural gas hedge contracts in place. Since we are exploring the possibility of selling our non-operated assets in the Piceance and DJ Basins, to which all of our natural gas hedges were attached, we liquidated our natural gas hedge positions during the fourth quarter for $2.0 million profit while they were in-the-money. We did not want to risk holding them into the heating season and have a run-up in the prices of natural gas, and subsequently have to liquidate them when they were out-of-the-money, requiring a cash outlay.

The impact that our other contractual obligations at December 31, 2008 are expected to have on our liquidity and cash flow in future periods is:

	One Year or Less	2 3 Years	4 5 Years	More than 5 Years
		(in thousands)		
Operating lease for office space	$ 372	$ 839	$ 867	$ 257
Senior bank facility line of credit (a)		29,650		
Interest on line of credit (b)	1,339	2,161		
10.75% Secured Convertible Debentures	750		25,500	
Interest on 10.75% Debentures	2,745	5,483	4,765	
Total contractual cash commitments	$ 5,206	$ 38,133	$ 31,132	$ 257

(a) The amount listed reflects the balance outstanding at December 31, 2008. Any balance outstanding at April 2, 2011 is due at that time.

(b) The interest rate assumed on the credit facility is 4.5% per annum, the rate in effect at December 31, 2008.

(c) The 10.75% Secured Convertible Debentures are due in their entirety on June 18, 2013.

Debt and Credit Facility

Secured Convertible Debentures

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

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

The net proceeds from the $30 million issuance of the Debentures, after fees and related expenses, were approximately $28 million. These funds were used to pay down the Company s outstanding indebtedness on its revolving credit facility.

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

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

In November 2008, one of the investors, who held a $3.75 million investment in the Debentures elected to convert their investment (see discussion under *Other Cash Requirements* above).

Credit Facility

In June 2007, we established a $50.0 million revolving credit facility with BNP Paribas (the Credit Facility) with an original maturity of June 15, 2010. The Credit Facility with BNP Paribas was replaced on August 9, 2007 by an amended and restated Credit Facility with JPMorgan Chase Bank, N.A. The amended and restated 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 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. At December 31, 2007, the Credit Facility had a borrowing base of $10.0 million with $8.0 million outstanding.

The Amended Credit Facility had an initial borrowing capacity of $50 million and was again amended on April 2, 2008 to a $150 million revolving credit facility ($50 million borrowing base) as a result of adding the additional reserves related to the acquisition of the Central Kansas Uplift properties previously discussed.

In connection with the privately placed 10.75% Secured Convertible Debentures, in June 2008, the borrowing base on our Amended Credit Facility was reduced to $32.5 million. On August 1, 2008 the borrowing base was re-determined and increased to $34.5 million, which was reaffirmed on the November 1, 2008 redetermination.

At December 31, 2008, our total available borrowings under the Debentures and Amended Credit Facility are $55.9 million.

Bank Covenants

We are subject to certain restrictive covenants in connection with our Amended Credit Facility. These covenants include selective financial covenants including working capital and our total debt to EBITDAX ratio. At December 31, 2008, we were in compliance with the covenants. Events or circumstances in the future may cause us to be out of compliance with these covenants (see expanded discussion above under Liquidity and Capital Resources). Should we fail to meet these covenants, measured at each quarterly reporting period, we may be required to obtain a waiver or an amendment to our current covenants. In the event that we are required to seek a waiver or amendment, we will be subject to re-determination of our credit facility at new lender-friendly terms. At December 31, 2008, our average interest rate on the outstanding borrowing on our Amended Credit Facility was 3.75%. An increase in this interest rate or a change in the timing of amounts due under our Amended Credit Facility may have a significant impact on our cash flows and abilities to fund our capital expenditures program. Refer to discussion regarding covenants under the heading Liquidity and Capital Resources.

Income Taxes, Net Operating Losses and Tax Credits

At December 31, 2008, we had net operating loss carryforwards, for federal income tax purposes, of approximately $59.5 million. These net operating loss carryforwards, if not utilized to reduce taxable income in future periods, will expire in various amounts beginning in 2018 through 2028. Approximately $2.2 million of such NOL s are subject to limitation under Section 382 of the Internal Revenue Code, all of which will free up in 2009. Under current income tax law, active drilling for oil and gas reserves generates tax deductions that are expected to offset any taxable income for the foreseeable future. Thus, we have established a valuation allowance for deferred taxes equal to our entire net deferred tax assets as management currently believes that it is more likely than not that these losses will not be utilized. The allowance recorded was $13.9 million and $10.0 million for 2008 and 2007, respectively.

Off-Balance Sheet Arrangements

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

From time to time, we enter into contracts that might be construed as off-balance sheet obligations but are normal in the day-to-day course of business in the oil and gas industry. Those contracts could include the contracts discussed directly above under Contractual Obligations. We do not believe we will be affected by these contracts materially differently than other similar companies in the energy industry.

Critical Accounting Policies and Estimates

This discussion and analysis of our financial condition and results of operations are based on the consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of our 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 Note 1 to the Consolidated Financial Statements, included in Item 8 of this Annual Report on Form 10-K. In the following discussion, we have identified the accounting estimates which we consider as the most critical to aid in fully understanding and evaluating our reported financial results. Estimates regarding matters that are inherently uncertain require difficult, subjective or complex judgments on the part of our management. We analyze our

estimates, including those related to oil and gas reserves, oil and gas properties, income taxes, contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe reasonable under the circumstances. Actual results may differ from these estimates.

Impairment of Oil and Gas Properties

We review the carrying values of our long-lived assets whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The long-lived assets of the Company, which are subject to periodic evaluation, consist primarily of oil and gas properties and undeveloped leaseholds. Refer to discussion of impairment charges recognized, by area, during the twelve months ended December 31, 2008 in Item 1 under the heading, Operations, Properties and Other Recent Events.

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 interpretation and judgment. Estimates of economically recoverable oil and natural 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 natural gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural 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 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.

Derivative Financial Instruments

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

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

Table of Contents

Successful Efforts Method of Accounting

We account for our natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and 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 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 which have targeted geologic structures which are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and gas leasehold acquisition costs may require 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 we are entering a new exploratory area in hopes of finding 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.

Stock-Based Compensation

During 2008, 3,224,363 performance share units, net of forfeitures, were granted to participants, pursuant to the 2005 Long Term Incentive Plan (LTIP) by the Compensation Committee of the Company s Board of Directors (the 2008 Grants). The 2008 Grants are scheduled to vest in three tranches, provided the goals set forth by the Compensation Committee are met. The performance measures under these Awards are based on increases in the Company s net asset value per share. The grants vest at 20%, 30% and 50% when the net asset value per share of the Company increases by 40%, 100% and 200%, respectively, from a base level set by the Compensation Committee as of December 31, 2007. Subsequent to the acquisition of the Central Kansas Uplift properties, the 40% increase in net asset value per share was reached, and the first 20% of the 2008 Grants vested. However, due to the instability of the economy, commodity prices and the capital markets, it appears improbable that any additional shares of the 2008 Grants will vest. An additional 295,549 shares of restricted common stock, net of forfeitures, granted pursuant to the Company s LTIP, were awarded, largely as an incentive to new employees, during the year ended December 31, 2008. These shares generally vest over three years based solely on service.

Compensation expense is recorded at fair value based on the market price of the Company s common stock at the date of grant and is recognized over the related service period. During the year ended December 31, 2008, we recorded $3.7 million for stock-based compensation expense applicable to the vesting of LTIP performance units (including the first tranche of the 2008 LTIP awards) and restricted stock grants.

Asset Retirement Obligations

Legal obligations associated with the retirement of long-lived assets result from the acquisition, construction, development and normal use of the asset. The Company s asset retirement obligations relate primarily to the retirement of oil and gas properties and related production facilities, lines and other equipment used in the field operations. The fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The estimated fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled.

Recently Adopted Accounting Pronouncements

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

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

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

New Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS No. 141R will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS No. 141R requires the acquiring company to measure almost all assets acquired and liabilities assumed in the acquisition at fair value as of the acquisition date. SFAS No. 141R is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied prospectively with the exception of income taxes which should be applied retrospectively for all business combinations. Early adoption is prohibited. We adopted SFAS No. 141(R) on January 1, 2009 and will apply its provisions to acquisitions on a go forward basis.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, (SFAS No. 161), an amendment to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. SFAS No. 161 requires enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. This Statement will be effective for our interim and annual financial statements beginning in fiscal year 2010. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. We plan to adopt the provisions of SFAS No. 161 effective January 1, 2009 and to report the required disclosures in our Form 10-Q for the period ending March 31, 2009.

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

In May 2008, the FASB issued FSP No. APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement, (FSP APB 14-1). FSP APB 14-1 addresses the accounting for convertible debt securities that, upon conversion, may be settled by the issuer either fully or partially in cash. FSP APB 14-1 is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied retrospectively to all past period presented. Early adoption is prohibited. The adoption of APB 14-1 effective January 1, 2009 will not have a material impact on our financial position or results of operations.

In June 2008, the FASB issued FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 clarified that all outstanding unvested share-based payment awards that contain rights to non-forfeitable dividends participate in undistributed earnings with common shareholders. Awards of this nature are considered participating securities and the two-class method of computing basic and diluted earnings per share must be applied. FSP EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. The adoption of FSP EITF 03-6-1 effective January 1, 2009 will not have a material impact on our consolidated financial statements or results of operations.

In June 2008, the FASB ratified the consensus reached by the EITF on Issue No. 07-5, Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own stock (EITF No. 07-5). EITF No. 07-5 provides guidance for determining whether an equity-linked financial instrument (or embedded feature) is indexed to an entity s own stock. EITF No. 07-5 applies to any freestanding financial instrument or embedded feature that has all of the characteristics of a derivative or freestanding instrument that is potentially settled in an entity s own stock. To meet the definition of indexed to own stock, an instrument s contingent exercise provisions must not be based on (a) an observable market, other than the market for the issuer s stock (if applicable), or (b) an observable index, other than an index calculated or measured solely by reference to the issuer s own operations, and the variables that could affect the settlement amount must be inputs to the fair value of a fixed-for-fixed forward or option on equity shares. EITF No. 07-5 is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of evaluating the impact of adoption of EITF 07-5 on our financial position and results of operations.

In June 2008, the FASB issued EITF 08-4, Transition Guidance for Conforming Changes to Issue No. 98-5 (EITF 08-4). EITF 08-4 provides transition guidance with respect to conforming changes made to EITF 98-5, that result from EITF 00-27, Application of Issue No. 98-5 to Certain Convertible Instruments, and SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. EITF 08-4 is effective for fiscal years ending after December 15, 2008. Early adoption is permitted. The adoption of EITF 98-5, effective January 1, 2009 will not have a material impact on our consolidated financial statements or results of operations.

In September 2008, the FASB ratified EITF Issue No. 08-5, Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement (EITF 08-5). EITF 08-5 provides guidance for measuring liabilities issued with an attached third-party credit enhancement (such as a guarantee). It clarifies that the issuer of a liability with a third-party credit enhancement (such as a guarantee) should not include the effect of the credit enhancement in the fair value measurement of the liability. EITF 08-5 is effective for the first reporting period beginning after December 15, 2008. The adoption of EITF 08-5, effective January 1, 2009 is not expected to have a material impact on our consolidated financial statements or results of operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS.

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 oil and natural gas prices, interest rates and the market price of our common stock. The disclosures are not meant to be precise indicators of expected future gains and losses, but rather indicators of reasonably possible gains and losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. 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 oil production and natural gas has been volatile and unpredictable for several years. The prices we receive for production depend on many factors outside of our control. For the year ended December 31, 2008, our net income would have changed by approximately $313 for each $0.50 change per Mcf in natural gas prices and approximately $45 for each $1.00 change per Bbl in crude oil prices.

Periodically, we enter into oil and natural gas derivative contracts to manage our exposure to oil and natural gas price volatility. At December 31, 2008 our derivative contracts consist of crude oil costless collars with effective dates through April 2013.

Our outstanding oil derivative contracts as of December 31, 2008 are summarized below:

Type of Contract	Remaining Volume	Fixed Price per Barrel	Price Index	Remaining Period
Oil Costless Collar	143,545	$90.00 Floor/$104.00 Ceiling	WTI	01/01/09-12/31/09
Oil Costless Collar	106,876	$90.00 Floor/$104.00 Ceiling	WTI	01/01/10-12/31/10
Oil Costless Collar	87,920	$90.00 Floor/$104.00 Ceiling	WTI	01/01/11-12/31/11
Oil Costless Collar	79,611	$90.00 Floor/$104.00 Ceiling	WTI	01/01/12-12/31/12
Oil Costless Collar	25,192	$90.00 Floor/$104.00 Ceiling	WTI	01/01/13-04/30/13
Total Bbl	443,144			

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. 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. For the crude oil contracts listed above, a hypothetical $1.00 change in the WTI price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the unrealized gain or loss on hedging activities in 2008 of $443. We plan to continue to enter into derivative contracts to decrease exposure to commodity price decreases.

At December 31, 2008 our oil and gas derivative contract asset balance was $12,208. Each period, we adjust this liability to fair value and recognize an unrealized gain or loss on oil and gas derivative contracts in our consolidated statement of operations.

Interest Rate Risk

At December 31, 2008, we had $29.7 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. At December 31, 2008, the interest rate on the credit facility borrowings, calculated in accordance with the agreement at .50% above the Prime rate, was 3.75%. Assuming no change in the amount outstanding as of December 31, 2008, 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 $297 per year.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Table of Contents

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Stockholders and Board of Directors
Teton Energy Corporation:

We have audited the accompanying consolidated balance sheets of Teton Energy Corporation and subsidiaries (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the three years ended December 31, 2008. We also have audited the Company s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting included in Item 9A. Our responsibility is to express an opinion on these financial statements and an opinion on the Company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Teton Energy Corporation and subsidiaries at December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the three years ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Teton Energy Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Ehrhardt Keefe Steiner & Hottman PC

Denver, Colorado
March 5, 2009

The accompanying notes are an integral part of the financial statements

Table of Contents

TETON ENERGY CORPORATION
Consolidated Balance Sheet

	December 31, 2008	December 31, 2007
	(in thousands)	
Assets		
Current assets:		
Cash and cash equivalents (Note 1)	$	$ 24,616
Trade accounts receivable	4,176	2,686
Tubular inventory	373	149
Fair value of oil and gas derivative contracts	5,217	
Prepaid expenses and other assets	249	131
Deferred debt issuance costs net	540	1,419
Total current assets	10,555	29,001
Oil and gas properties, successful efforts method:		
Developed properties	94,529	35,708
Wells and facilities in progress	7,702	3,230
Undeveloped properties	22,005	13,411
Corporate and other assets	1,460	485
Total property and equipment	125,696	52,834
Less accumulated depreciation and depletion	(18,317)	(3,695)
Net property and equipment	107,379	49,139
Fair value of oil and gas derivatives contracts	6,991	
Deferred debt issuance costs net	1,933	159
Total assets	126,858	78,299
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	1,915	400
Accrued liabilities	6,272	7,833
Accrued payroll	202	902
8% senior subordinated convertible notes, net of discount of $7,370 at December 31, 2007		1,630
Fair value of oil and gas derivative contracts		455
Derivative warrant liabilities		9,522
Total current liabilities	8,389	20,742
Long-term liabilities:		

Long-term debt senior secured bank debt	29,650	8,000
Long-term debt 10.75% Secured Convertible Debentures	26,250	
Asset retirement obligations	1,298	529
Total long-term liabilities	57,198	8,529
Total liabilities	65,587	29,271
Commitments and contingencies (see Note 11)		
Stockholders equity:		
Preferred stock, $.001 par value; 25,000,000 shares authorized; none outstanding		
Common stock, $.001 par value; 250,000,000 shares authorized; 23,821,573 and 17,652,889 shares issued and outstanding as of December 31, 2008 and 2007, respectively	24	18
Additional paid-in capital	103,267	76,857
Accumulated deficit	(42,020)	(27,847)
Total stockholders equity	61,271	49,028
Total liabilities and stockholders equity	126,858	78,299

The accompanying notes are an integral part of the financial statements

Table of Contents

TETON ENERGY CORPORATION
Consolidated Statement of Operations

	Years Ended December 31, 2008	2007	2006
	(in thousands, except per share amounts)		
Operating revenues:			
Oil and gas sales	$ 28,469	$ 6,253	$ 4,022
Gain on sale of oil and gas properties		17,441	
Miscellaneous Income, net	341		
Total revenues	28,810	23,694	4,022
Operating expenses:			
Lease operating expense	4,247	705	325
Workover Expense	234		
Transportation expense	1,827	652	493
Production taxes	1,932	412	251
Exploration expense	4,831	1,847	448
General and administrative	9,588	8,981	7,148
Depreciation, depletion and accretion expense	14,625	3,832	1,749
Impairment expense	14,260		
Total operating expenses	51,544	16,429	10,414
Operating income (loss)	(22,734)	7,265	(6,392)
Other income (expense):			
Realized gain on oil and gas derivative contracts	1,349	1,181	
Unrealized gain (loss) on oil and gas derivative contracts	12,662	(857)	403
Gain (loss) on derivative contract liabilities	7,762	(2,624)	
Interest income (expense), net	(11,976)	(2,588)	265
Interest make-whole premium on conversion of debt (Note 5)	(1,236)		
Total other income (expense)	8,561	(4,888)	668
Net income (loss) applicable to common shares	$ (14,173)	$ 2,377	$ (5,724)
Basic income (loss) per common share	$ (0.67)	$ 0.14	$ (0.44)
Fully diluted income (loss) per common share	$ (0.67)	$ 0.13	$ (0.44)

Basic weighted-average common shares outstanding	21,064	16,545	13,093
Fully diluted weighted-average common shares outstanding	21,064	18,061	13,093

The accompanying notes are an integral part of the financial statements

Table of Contents

TETON ENERGY CORPORATION
Consolidated Statement of Cash Flows

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Operating activities:			
Net income (loss)	$ (14,173)	$ 2,377	$ (5,724)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and accretion	14,625	3,832	1,749
Impairment of oil and gas properties	14,260		
Lease Expirations	3,401		
Debt issuance cost amortization	1,886	586	
Debt discount amortization	7,370	1,630	
Stock-based compensation expense, exclusive of cash withheld for payroll taxes of $779, $700 and $0, respectively	2,890	2,588	2,928
Stock issued for outside services, net		264	53
Non-cash loss on derivative contract liabilities	(7,762)	2,624	
Unrealized loss (gain) oil and gas derivative contracts	(12,662)	857	(403)
Stock Issued for Interest Make-Whole related to Conversion of 10.75% Convertible Debt (Note 5)	279		
Gain on sale of oil and gas properties		(17,441)	
Changes in current assets and liabilities:			
Trade accounts receivable	(1,490)	(1,173)	(612)
Advances to operator			(177)
Prepaid expenses and other current assets	(343)	10	(153)
Accounts payable and accrued liabilities	1,513	1,767	66
Accrued payroll	(700)	11	494
Net cash provided by operating activities	9,094	(2,068)	(1,779)
Investing activities:			
Proceeds from sale of oil and gas properties		35,125	2,700
Acquisition of corporate fixed assets	(949)	(89)	(182)
Acquisition and development of oil and gas properties	(76,945)	(35,635)	(20,355)
Net cash used in investing activities	(77,894)	(599)	(17,837)
Financing activities:			
Proceeds from issuance of common stock and warrants net of offering costs of $0, $368 and $1,127, respectively		4,500	10,834
Proceeds from exercise of options/warrants	1,915	2,408	6,235
Proceeds from 8% Senior Subordinated Convertible Notes		9,000	
Proceeds from 10.75% Convertible debt (Note 5)	30,000		
Net borrowings from senior bank credit facility	21,650	8,000	

Payments on 8% Convertible Notes	(6,600)		
Debt issuance costs	(2,781)	(950)	(192)
Net cash provided by financing activities	44,184	22,958	16,877
Increase (decrease) in cash and cash equivalents	(24,616)	20,291	(2,739)
Cash and cash equivalents beginning of period	24,616	4,325	7,064
Cash and cash equivalents end of period	$	$ 24,616	$ 4,325

The accompanying notes are an integral part of the financial statements

F-4

Table of Contents

TETON ENERGY CORPORATION
Consolidated Statement of Cash Flows (continued)

	Years Ended December 31, 2008	2007 (in thousands)	2006
Supplemental disclosure of cash and non-cash transactions:			
Cash paid for interest, net of amounts capitalized	$ 1,859	$ 694	$
Cash paid for interest make-whole premium on conversion of debt	$ 957	$	$
Capitalized interest	$ 372	$ 121	$
Stock-based compensation expense included in capital expenditures	$	$	$
Sales of oil and gas properties included in accounts receivable	$	$ 652	$
Deposits and advances applied to oil and gas properties	$	$ 401	$ 300
Accrued purchase consideration recorded as oil and gas properties	$	$	$ 775
Capital expenditures included in accounts payable and accrued liabilities	$ 4,107	$5,667	$4,933
ARO additions, revisions and acquired obligations	$ 740	$ 241	$ 50
Placement agent warrants recorded as equity issuance costs	$	$ 190	$
Placement agent warrants recorded as debt issuance costs	$	$1,023	$
Reclassification of derivative liabilities to stockholder s equity	$	$3,124	$
Conversion of 8% Subordinated Debt into Common Stock	$ 2,400	$	$
Conversion of 10.75% Convertible Debt into Common Stock	$ 3,750	$	$
Common Stock and Warrants issued in connection with the acquisition of oil and gas properties	$13,423	$	$

The accompanying notes are an integral part of the financial statements

F-5

Table of Contents

TETON ENERGY CORPORATION
Consolidated Statement of Changes in Stockholders Equity

	Preferred Stock Shares	Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholders Equity
			(in thousands)				
Balance-December 31, 2005		$	11,329	$ 11	$ 43,930	$ (24,500)	$ 19,441
Warrants and options exercised			1,531	2	6,234		6,236
Sale of common stock, net			2,300	2	10,831		10,833
Return of common stock			(50)		(158)		(158)
Stock-based compensation			463	1	2,927		2,928
Common stock issued for services			34		211		211
Net loss for year						(5,724)	(5,724)
Balance-December 31, 2006			15,607	16	63,975	(30,224)	33,767
Options exercised			673	1	2,404		2,405
Warrants exercised			2		3		3
Sale of common stock, net of offering costs of $368			964	1	4,499		4,500
Stock-based compensation, exclusive of amounts withheld for payroll taxes			364		2,588		2,588
Common stock issued for services			43		264		264
Reclassification of derivative liabilities					3,124		3,124
Net income for year						2,377	2,377
Balance-December 31, 2007			17,653	18	76,857	(27,847)	49,028
Warrants and options exercised			599	1	1,914		1,915
Warrant Exchange Agreement			990	1	1,758		1,759
Conversion of 8% Subordinated Debt into Common Stock			480		2,400		2,400
Common stock issued upon conversion of $3.75 million 10.75%			794	1	4,028		4,029

Secured Convertible Debentures (Note 5)						
Common Stock issued in connection with the acquisition of oil and gas properties		2,746	3	13,420		13,423
Stock-based compensation for Performance Share Units, exclusive of amounts withheld for payroll taxes		457		2,010		2,010
Stock-based compensation for Restricted Stock, exclusive of amounts withheld for payroll taxes		102		880		880
Net loss for year					(14,173)	(14,173)
Balance-December 31, 2008	$	23,821	$ 24	$ 103,267	$ (42,020)	$ 61,271

The accompanying notes are an integral part of the financial statements

F-6

Table of Contents

Note 1 Business Description and Summary of Significant Accounting Policies

Teton Energy Corporation (Teton or the Company) was formed in November 1996 and is incorporated in the State of Delaware. Teton is an independent oil and gas exploration and production company focused on the acquisition, exploration and development of North American properties. The Company s current operations are concentrated in the prolific Midcontinent and Rocky Mountain regions of the U.S. The Company has leasehold interests in the Central Kansas Uplift, the Piceance Basin in western Colorado, the eastern Denver-Julesburg Basin in Colorado, Kansas and Nebraska, the Williston Basin in North Dakota and the Big Horn Basin in Wyoming.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Teton and its wholly owned subsidiaries Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton DJCO LLC, Teton Williston LLC, and Teton Big Horn LLC. All inter-company accounts and transactions have been eliminated in consolidation.

Through February 28, 2007, the Company consolidated its investment in Piceance Gas Resources, LLC, a Colorado limited liability company (Piceance LLC), using pro rata consolidation, whereby the Company included its 25% pro rata share of Piceance LLC s assets, liabilities, revenues, expenses and oil and gas reserves in its financial statements. During the first quarter of 2007, the members of Piceance LLC applied to and received the consent of the fee owner of the land on which Piceance LLC s oil and gas rights and leases are located for Piceance LLC to transfer the underlying interest directly to each of the members.

The Company has no interests in any unconsolidated entities, nor does it have any unconsolidated special purpose entities.

Certain amounts in previous financial statement were reclassified to conform to the 2008 consolidated financial statement presentation.

Cash and Cash Equivalents

Cash and cash equivalents includes all cash balances and any highly liquid investments with an original maturity of 90 days or less. The Company uses cash on-hand to repay, to the extent possible, amounts outstanding under its line of credit, and minimize related interest expense, resulting in a cash balance of $0 at December 31, 2008.

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of its join interest partners on operated properties in its accounts receivable balance. Management periodically reviews accounts receivable amounts for collectability. No allowance for doubtful accounts was considered necessary at December 31, 2008, 2007 and 2006.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure on contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimated by management. Estimates of oil and gas reserve quantities provide the basis for the calculation of depreciation and depletion, and impairment, each of which represents a significant component of the consolidated financial statements.

Revenue Recognition

Revenues are recognized when oil and natural gas are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is probable.

Table of Contents

Gas Balancing

Teton uses the sales method of accounting for gas revenue whereby natural gas revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company s ownership in the property. A liability is recognized to the extent that there is an imbalance in excess of the remaining gas reserves on the underlying properties. The Company did not have any gas imbalances at December 31, 2008 and 2007.

Oil and Gas Producing Activities

Teton uses the successful efforts method of accounting for its oil and gas producing activities. Under this method of accounting, all property acquisition costs and costs of exploration and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive.

Geological and geophysical costs and the costs of carrying and retaining unproved leaseholds are expensed as incurred. The Company limits the total amount of unamortized capitalized costs for each proved property to the value of future net revenues, based on current prices and costs.

Depletion of capitalized costs for producing oil and gas properties is provided on a field-by-field basis using the units-of-production method, based on proved oil and gas reserves. Depletion takes into consideration restoration, dismantlement and abandonment costs and the anticipated proceeds for equipment salvage. Some of the Company s producing facilities, consisting of natural gas pipelines and water disposal wells, are depreciated utilizing the straight-line method over remaining useful lives, consistent with the life of the field, of 13 to 25 years as of December 31, 2008.

Depreciation and depletion of oil and gas properties for the years ended December 31, 2008, 2007 and 2006, was $14.6 million, $3.8 million and $1.7 million, respectively.

Teton invests in unevaluated oil and gas properties for the purpose of exploration and subsequent development of proved reserves. The costs of unproved leases which become productive are reclassified to proved properties when proved reserves are discovered on the property. Unproved oil and gas properties are carried at the lower of cost or estimated fair market value and are not subject to amortization.

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 depletion rate. A gain or loss is recognized for all other sales of proved or unproved properties.

The following table reflects the net changes in capitalized exploratory well costs during the year ended December 31, 2008 (amounts in thousands). The Company had no exploratory wells in progress as of December 31, 2007 and 2006.

	2008
Beginning balance at January 1, 2008	$
Additions to capitalized exploratory well costs pending the determination of proved reserves	530
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	
Capitalized exploratory well costs charged to expense	
Ending balance at December 31, 2008	$ 530

Amounts capitalized at December 31, 2008 relate to the Viall #1-30 well which was spud on November 13, 2008 in the Company s Goliath project in the Williston Basin to test the Stonewall, Red River and Winnipeg formations. The drilling rig was released on December 16, 2008 and moved off location on December 22, 2008. Completion operations commenced on January 5, 2009. As of February 12, 2009, testing of the Winnipeg formation did not

Table of Contents

indicate commercially viable production from that formation, and the Company moved up-hole to test the Red River and Stonewall formations, which is still in process. The Company had no exploratory wells in progress for a period of greater than one year as of December 31, 2008.

Under the provisions of the Financial Accounting Standards Board (the FASB) Staff Position 19-1 (FAS 19-1), a company under the successful efforts method of accounting may continue to capitalize exploratory well costs if there are sufficient quantities of reserves to justify completion of the well or if the company is making significant progress towards assessing the quantities of reserves.

Asset Retirement Obligations

Legal obligations associated with the retirement of long-lived assets result from the acquisition, construction, development and normal use of the asset. The Company s asset retirement obligations relate primarily to the retirement of oil and gas properties and related production facilities, lines and other equipment used in the field operations. The estimated fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The estimated fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled.

For the years ended December 31, 2008, 2007 and 2006, an expense of $29, $43 and $24, respectively, was recorded as accretion expense on the liability and included in depreciation, depletion and accretion. During 2008 and 2007, the Company recorded an additional $285 and $189, respectively, in oil and gas properties and asset retirement obligation liability to reflect the present value of plugging liability on new wells, and $193 and $239, respectively, on obligations acquired.

A reconciliation of the Company s asset retirement obligation liability:

	Year Ended December 31,	
	2008	2007
	(in thousands)	
Asset retirement obligation beginning of period	$ 529	$ 78
Additional liabilities incurred	285	189
Revisions in estimated cash flows	262	52
Obligations settled		
Accretion expense	29	43
Obligations acquired	193	239
Obligations sold		(72)
Asset retirement obligation end of period	$ 1,298	$ 529

Deferred Debt Issuance Costs

Deferred debt issuance costs are amortized to interest expense over the life of the related debt instrument or credit facility using the effective interest method.

Capitalized Interest

Interest incurred on funds borrowed to finance certain acquisition and development activities is capitalized. To qualify for interest capitalization, the costs incurred must relate to the acquisition of unproved reserves, drilling of wells to prove up the reserves and the installation of the necessary pipelines and facilities to make the property ready for production. Such capitalized interest is included in oil and gas properties. Capitalized interest is amortized over the estimated life of the respective project.

Corporate and Other Assets

Fixed assets are stated at cost. Depreciation is provided utilizing the straight-line method over the estimated useful lives ranging from three to seven years.

Table of Contents

Impairment of Long-Lived Assets

The Company reviews the carrying values of its long-lived assets whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If, upon review, the sum of the estimated undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The long-lived assets of the Company, which are subject to periodic evaluation, consist primarily of oil and gas properties including undeveloped leaseholds. The Company incurred impairment expenses of $14.3 million, $0 and $0 during the years ended December 31, 2008, 2007 and 2006, respectively.

As of December 31, 2008 there were 124 producing wells, 5 wells waiting on completion and four waiting on pipeline in the Company s non-operated properties in the Teton-Noble AMI in the DJ Basin. The production from these wells, which is currently lower than expected, has resulted in lower reserve estimates being assigned to the wells. The carrying value of the Teton-Noble AMI developed properties exceeded the undiscounted future net revenues estimated to be derived from the wells. As a result, the Company has determined that $8.6 million of capitalized costs (the amount by which the carrying value exceeds the fair value) related to the non-operated properties in the Teton-Noble AMI is impaired, and that amount has been charged to expense during the year ended December 31, 2008. The fair value was determined as the discounted net present value of the future cash flows using a 10% discount factor. Additionally, the carrying value of the undeveloped acreage for the Teton-Noble AMI exceeded its fair value by $3.2 million, and that amount has also been charged to expense during the year ended December 31, 2008. The Company also recorded impairment expense related to the Washco producing properties of $2.4 million and impairment expense related to our Frenchman Creek acreage block in the DJ Basin of $100.

Accrued Liabilities

At December 31, 2008 and 2007 accrued liabilities consisted of $1.7 million of accrued interest payable related to the Company s 10.75% Secured Convertible Debentures and interest on the balance outstanding on its line of credit and $80 related to interest on the balance outstanding on its line of credit, $856 and $428 of accrued production taxes related to oil and gas sales $3.7 million of accrued liabilities related to operations respectively.

Income (Loss) per Common Share

Basic income (loss) per common share is computed by dividing net income (loss) by the weighted average number of basic common shares outstanding during each period. The shares represented by vested restricted stock and vested performance share units under the Company s 2005 Long Term Incentive Plan (see Note 8) are considered issued and outstanding at December 31, 2008 and 2007, respectively, and are included in the calculation of the weighted average basic common shares outstanding. Diluted income per common share reflects the potential dilution that would occur if contracts to issue common stock were exercised or converted into common stock.

Stock-Based Compensation Expense

Effective January 1, 2007, Teton adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 123R Share-Based Payment (revised 2004) (SFAS No. 123R), which requires the measurement and recognition of compensation expense for all share-based payment awards (including stock options) made to employees and directors based on estimated fair value. Compensation expense for equity-classified awards is measured at the grant date based on the fair value of the award and is recognized as an expense in earnings over the requisite service period. The Company adopted SFAS No. 123R using the modified prospective transition method. Under this transition method, compensation cost recognized during the year ended December 31, 2008 and 2007 included the cost for options which were granted prior to January 1, 2007, as determined under the provisions of SFAS No. 123. See Note 8 below.

Prior to the adoption of the provisions of SFAS No. 123R, Teton accounted for employee stock-based compensation expense under Accounting Principles Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees (APB No. 25), and related interpretations, as permitted by SFAS No. 123, Accounting for Stock-Based Compensation APB No. 25 did not require any compensation expense to be recorded in the financial statements if

the exercise price of the employee stock-based compensation award was equal to or greater than the market price of the stock on the date of grant. Prior to July 2005, the Company had only issued stock options as employee stock-based compensation 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, 2007.

Derivative Financial Instruments

The Company uses derivative financial instruments to mitigate exposures to oil and gas production cash-flow risks caused by fluctuating commodity prices. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as liabilities or assets on the balance sheet. For oil and gas derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in the consolidated statement of operations. When oil and gas derivative contracts are settled, the Company recognizes realized gains and losses under the other income and expense caption in its consolidated statement of operations. At December 31, 2008, 2007, and 2006, the Company did not have any derivative contracts that qualify as cash flow hedges.

The Company also uses various types of financing arrangements to fund its business capital requirements, including convertible debt and other financial instruments indexed to the market price of the Company s common stock. Teton evaluates these contracts to determine whether derivative features embedded in host contracts require bifurcation and fair value measurement or, in the case of free-standing derivatives (principally warrants), whether certain conditions for equity classification have been achieved. In instances where derivative financial instruments require liability classification, the Company initially and subsequently measures such instruments at estimated fair value. Accordingly, the Company adjusts the estimated fair value of these derivative components at each reporting period through a charge to earnings until such time as the instruments are exercised, expire or are permitted to be classified in stockholders equity. See Note 5 below.

Income Taxes

The Company recognizes deferred tax assets and liabilities based on the differences between the tax basis of assets and liabilities and their reported amounts in the financial statements that may result in taxable or deductible amounts in future years. The measurement of deferred tax assets may be reduced by a valuation allowance based upon management s assessment of available evidence if it is deemed more likely than not some or all of the deferred tax assets will not be realizable. Currently, a valuation allowance of 100% is provided for the deferred tax asset resulting from the Company s net operating loss carry forward in each of the reporting years.

Significant Customers

The Company had oil and gas sales to two customers accounting for 62% and 28%, respectively, of total oil and gas revenues for the year ended December 31, 2008. The Company had oil and gas sales to one major customer (a different customer in each year) accounting for 77% and 92%, respectively, of total oil and gas revenues for the years ended December 31, 2007 and 2006. The Company believes that it is not dependent upon any of these customers due to the nature of its product. No other single customer accounted for 10% or more of revenues in 2008, 2007 or 2006.

Concentrations of Credit Risk

Substantially all of the Company s accounts receivable are due from purchasers of oil and natural gas or operators of the oil and gas properties. Oil and natural gas sales are generally unsecured. The Company has not experienced any meaningful credit losses in prior years and is not aware of any uncollectible accounts at December 31, 2008 or 2007. Derivative financial instruments that hedge the price of oil and gas are generally executed with major financial or commodities trading institutions which expose the Company to market and credit risks and may, at times, be concentrated with one counterparty. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk, in the event of non-performance by the counterparty, are substantially smaller. The credit worthiness of counterparties is subject to continuing review and full performance is anticipated. At December 31, 2008, all of the Company s derivative financial instruments are hedging the price of crude oil and are with JPMorgan Venture Energy Corporation as the counterparty.

The Company continually monitors its positions with, and the credit quality of, the financial institutions with which it invests. As of the balance sheet date, and periodically throughout the year, the Company has maintained balances in various accounts in excess of federally insured limits.

Recently Adopted Accounting Pronouncements

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

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

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

New Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS No. 141R will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS No. 141R requires the acquiring Company to measure almost all assets acquired and liabilities assumed in the acquisition at fair value as of the acquisition date. SFAS No. 141R is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied prospectively with the exception of income taxes which should be applied retrospectively for all business combinations. Early adoption is prohibited. The Company adopted SFAS No. 141(R) on January 1, 2009 and will apply its provisions to future acquisitions.

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

SFAS No. 161 effective January 1, 2009 and will report the required disclosures in its Form 10-Q for the period ending March 31, 2009.

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

In May 2008, the FASB issued FSP No. APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement, (FSP APB 14-1). FSP APB 14-1 addresses the accounting for convertible debt securities that, upon conversion, may be settled by the issuer either fully or partially in cash. FSP APB 14-1 is effective for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company) and should be applied retrospectively to all past period presented. Early adoption is prohibited. The adoption of APB 14-1 effective January 1, 2009 will not have a material impact on the Company s financial position or results of operations.

In June 2008, the FASB issued FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 clarified that all outstanding unvested share-based payment awards that contain rights to non-forfeitable dividends participate in undistributed earnings with common shareholders. Awards of this nature are considered participating securities and the two-class method of computing basic and diluted earnings per share must be applied. FSP EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. The adoption of FSP EITF 03-6-1 effective January 1, 2009 will not have a material impact on the Company s consolidated financial statements or results of operations.

In June 2008, the FASB ratified the consensus reached by the EITF on Issue No. 07-5, Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own stock (EITF No. 07-5). EITF No. 07-5 provides guidance for determining whether an equity-linked financial instrument (or embedded feature) is indexed to an entity s own stock. EITF No. 07-5 applies to any freestanding financial instrument or embedded feature that has all of the characteristics of a derivative or freestanding instrument that is potentially settled in an entity s own stock. To meet the definition of indexed to own stock, an instrument s contingent exercise provisions must not be based on (a) an observable market, other than the market for the issuer s stock (if applicable), or (b) an observable index, other than an index calculated or measured solely by reference to the issuer s own operations, and the variables that could affect the settlement amount must be inputs to the fair value of a fixed-for-fixed forward or option on equity shares. EITF No. 07-5 is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. The Company is in the process of evaluating the impact of adoption of EITF 07-5 on its financial position and results of operations.

In June 2008, the FASB issued EITF 08-4, Transition Guidance for Conforming Changes to Issue No. 98-5 (EITF 08-4). EITF 08-4 provides transition guidance with respect to conforming changes made to EITF 98-5, that result from EITF 00-27, Application of Issue No. 98-5 to Certain Convertible Instruments, and SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. EITF 08-4 is effective for fiscal years ending after December 15, 2008. Early adoption is permitted. The adoption of EITF 98-5, effective January 1, 2009 will not have a material impact on the Company s consolidated financial statements or results of operations.

In September 2008, the FASB ratified EITF Issue No. 08-5, Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement (EITF 08-5). EITF 08-5 provides guidance for measuring liabilities issued with an attached third-party credit enhancement (such as a guarantee). It clarifies that the issuer of a liability with a third-party credit enhancement (such as a guarantee) should not include the effect of the credit enhancement in the fair value measurement of the liability. EITF 08-5 is effective for the first reporting period beginning after December 15, 2008. The adoption of EITF 08-5, effective January 1, 2009 is not expected to have a material impact on the Company s consolidated financial statements or results of operations.

Table of Contents

Note 2 Income (Loss) per Common Share
The following table summarizes the calculation of basic and fully diluted income (loss) per common share:

	Years Ended December 31,		
	2008	2007	2006
	(in thousands, except per share data)		
Net income (loss) applicable to common shares	$ (14,173)	$ 2,377	$ (5,724)
Adjustments for avoidable interest			
Adjusted Net income (loss)	$ (14,173)	$ 2,377	$ (5,724)
Weighted average common shares outstanding basic	21,064	16,545	13,093
Add dilutive effect of:			
LTIP performance share units 2007 Plan		445	
LTIP performance-vesting restricted common stock 2008 Plan		373	
LTIP restricted common stock		13	
Stock options		393	
Warrants		292	
Weighted average common shares outstanding diluted	21,064	18,061	13,093
Basic income (loss) per common share	$ (0.67)	$ 0.14	$ (0.44)
Fully diluted income (loss) per common share	$ (0.67)	$ 0.13	$ (0.44)

The following securities that could be potentially dilutive in future periods were not included in the computation of fully diluted income (loss) per common share because the effect would have been anti-dilutive for the periods indicated:

	Years Ended December 31,		
	2008	2007	2006
Convertible Notes	3,467,487	1,800,000	
Warrants	1,125,003	4,374,547	867,819
Stock Options	125,220		2,088,545
LTIP Performance Units			1,911,000
Restricted Common Stock	68,467		193,999
Total	4,786,177	6,174,547	5,061,363

The above amounts are calculated using the treasury stock method, whereby a company uses the proceeds from the exercise or purchase of shares as well as the average unrecognized compensation to repurchase common stock at the average market price during the period. This is the prescribed method used to calculate the dilutive shares in fully diluted earnings per share calculations. At December 31, 2008, the maximum number of shares that could potentially be included in the basic earnings per share calculation, if all shares above were exercised, purchased or converted is 9,452,890 shares.
Due to the instability of the economy and the capital markets, and the depressed oil and natural gas prices at December 31, 2008, the Compensation Committee voted to terminate the 2006 and 2007 LTIP Plans, and no future

vesting will occur under either of those plans. Additionally, it is improbable that future vesting in the 2008 LTIP Plan will occur. Thus, potentially dilutive shares are not considered in the table above for the LTIP Plans for the year ended December 31, 2008.

Table of Contents

Note 3 Acquisitions of Oil and Gas Properties

2008 Acquisition

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

The purchase price was funded with $40.2 million of cash and borrowing capacity available under Teton s revolving credit facility with JPMorgan Chase (see Note 6), $13.0 million of Teton common stock, or 2,746,128 common shares, and 625,000 warrants valued at $434. Effective April 2, 2008, Teton amended its bank credit facility with JPMorgan, increasing the total facility from $50 million to $150 million. The available borrowing base under Teton s bank credit facility was increased from $10 million to $50 million as a result of the combination of the added reserves from this transaction, ongoing drilling programs and new commodity hedging positions. The Company hedged 80 percent of the oil proved developed producing (PDP) production and 80 percent of the natural gas PDP production related to this transaction for five years through a series of costless collars in order to lock in base case economics associated with the acquisition.

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

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

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

The Company included the revenues and expenses applicable to the properties sold in its results of operations beginning April 1, 2008.

The following summarized pro forma information gives effect to the acquisition of the interests of Shelby by Teton as if the assets had been acquired as of January 1, 2008 and 2007.

	Year Ended December 31,	
	2008	2007
Revenues	$ 31,960	$34,953
Income from continuing operations	$(13,477)	$ 915
Earnings per share from continuing operations basic	$ (0.64)	$ 0.05
Earnings per share from continuing operations diluted	$ (0.64)	$ 0.04

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

Table of Contents

2007 Acquisitions and Dispositions

In 2007, the Company acquired a 100% working interest in 16,417 gross acres (15,132 net) in the Big Horn Basin in the state of Wyoming for $1.0 million. The Company will serve as the operator for this project.

On October 1, 2007, the Company closed on an Asset Exchange Agreement (the Exchange Agreement) with Delta Petroleum Corporation (Delta). The Exchange Agreement provided for an economic effective date of July 1, 2007. Pursuant to the Exchange Agreement the Company sold to Delta a 12.5% working interest position, or one-half of its 25% working interest position, in certain oil and gas rights and leasehold assets covering 6,314 gross acres in the Piceance Basin in Western Colorado, for a sales price of $33.0 million in cash (before normal closing adjustments) and all of Delta s rights, title and interest in certain proved producing oil and gas properties and undeveloped acreage located in the DJ Basin, which Teton valued at $5.0 million at July 1, 2007 (net of asset retirement obligations assumed).

The Company included the revenues and expenses applicable to the properties sold in its results of operations through September 30, 2007. The Company also recorded capital expenditures applicable to the properties sold through September 30, 2007. Delta reimbursed the Company for capital expenditures and certain operating expenses, net of applicable revenues, that the Company incurred during the period July 1, 2007 through September 30, 2007 in the amount of approximately $3.0 million and approximately $700,000 of additional reimbursements were included in trade accounts receivable on the Consolidated Balance Sheet at December 31, 2007.

During the period July 1, 2007 through September 30, 2007, the Company reimbursed Delta for its capital expenditures and certain operating expenses, net of applicable revenues, associated with the oil and gas properties acquired in the amount of $482,000.

The purchase price of the DJ Basin properties acquired was allocated as follows:

	As of October 1, 2007 (in thousands)	
Proved oil and gas properties	$	4,343
Unproved oil and gas properties		362
Fixed assets		13
Less:		
Asset retirement obligation		239
Net purchase price	$	4,479

The related 2007 gain on sale of oil and gas properties is as follows:

	For the Year Ended December 31, 2007 (in thousands)	
Cash component of initial sales price	$	33,000
Sales price adjustments applicable to oil and gas properties sold		3,682
Initial price of oil and gas properties acquired including asset retirement obligations		5,200
Sales price adjustments applicable to oil and gas properties acquired		(482)
Less:		
Transaction costs, net of $ 169,000 capitalized		1,287
Asset retirement obligation assumed with oil and gas properties acquired		239
Asset retirement obligation assumed by purchaser with properties sold		(72)
Carrying value of properties sold as of October 1, 2008		22,505

Gain on sale of oil and gas properties	$	17,441

In November 2007, the Company acquired an additional leasehold interest in the Denver-Julesburg Basin, in proximity to its current projects in Nebraska and eastern Colorado. Teton entered into an agreement to acquire the sellers interest in 168,197 gross acres (160,689 net). The purchase price is approximately $1.3 million gross and approximately $1.0 million net to Teton after all partners exercised their options within the two areas of mutual interest. At December 31, 2007, the Company had spent $984,000 toward the purchase price and received $188,000 from partners, and the remaining expenditures and receipts occurred in early 2008.

At December 31, 2007, trade accounts receivable includes $652,000 applicable to the sale of oil and gas properties.

2006 Acquisitions and Dispositions

On January 27, 2006, the Company closed an Acreage Earning Agreement (the Earning Agreement) with Noble Energy, Inc. (Noble), with an effective date of December 31, 2005. Teton received $3.0 million from Noble and recorded this payment as a reduction to its investment in its DJ Basin oil and gas properties. Effective December 18, 2007, Noble earned a 75% working interest in these properties by drilling and completing 20 wells in the acreage covered by the Earning Agreement. Teton is entitled to 25% of the net revenues applicable to those first 20 wells. After completing the first 20 wells, the Earning Agreement provides that Teton and Noble split all costs associated with future drilling and development activities in accordance with each party s working interest percentage.

On May 5, 2006, the Company acquired a 25% working interest in approximately 87,192 gross acres in the Williston Basin located in North Dakota for a total purchase price of $6.2 million from American Oil & Gas, Inc. (American). The Company paid American $2.5 million at closing and an additional $3.7 million prior to June 1, 2007 for American s 50% share of drilling and completion costs applicable to two new wells. In addition to the obligation to fund American s share, the Company was also obligated to pay its 25% share of drilling and completion costs of such wells.

Note 4 Fair Value of Financial Instruments

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

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

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

Level 3 Significant inputs to the valuation model are unobservable.

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

Debt and Equity Securities

The recorded value of the Company s senior secured bank debt approximates its fair value as it bears interest at a floating rate. The Company s Secured Convertible Notes (Convertible Notes) are presented at face value on the Consolidated Balance Sheet. The Company did not make any fair value elections under SFAS No. 159 with respect to the Convertible Notes. The Company is in the process of evaluating EITF 07-5 (which is effective for the Company starting January 1, 2009) to determine if the conversion features embedded in the Convertible Notes require derivative accounting.

Derivative Instruments

The Company uses derivative financial instruments to mitigate exposures to oil and gas production cash flow risks caused by fluctuating commodity prices. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as liabilities or assets on the balance sheet. For oil and gas derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in the consolidated statement of operations. When oil and gas derivative contracts are settled, the Company recognizes realized gains and losses under the other income and expense caption in its consolidated statement of operations. At December 31, 2008, 2007 and 2006, respectively, the Company did not have any derivative contracts that qualify as cash flow hedges.

Table of Contents

Derivative assets and liabilities included in Level 2 include hedge contracts, valued using the Black-Scholes-Merton valuation technique, in place through April 2013 for a total of approximately 443,144 Bbls of oil production.

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

Prior to October 7, 2008, the Company had in place warrants to purchase 3,600,000 shares of the Company s common stock that did not achieve all of the requisite conditions for equity classification and were reported at fair value as a component of current liabilities. These free-standing derivative financial instruments arose in connection with the Company s financing transaction in May 2007 which consisted of the $9.0 million Convertible Notes and warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price for a period of five years (with a cashless exercise option). Effective October 7, 2008, the Company and all of the investors that held the 3,600,000 warrants agreed to exchange the warrants for 900,000 shares of the Company s common stock. As a result, the carrying value of the current liability for the financing warrants was reduced to the fair value, resulting in a realized gain of $7,762 that is included in the Consolidated Statement of Operations.

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

The following table summarizes Teton s assets and liabilities measured at fair value on a recurring basis at December 31, 2008.

	Level 1	Level 2	Level 3	Total
Assets:				
Oil and gas derivative contracts	$	$ 12,208	$	$ 12,208
Liabilities:				
Oil and gas derivative contracts	$	$	$	$
Derivative contracts Warrants				
	$	$	$	$

Changes in estimated fair value of derivative assets and liabilities

During the twelve months ended December 31, 2008, the Company recorded $12,662 related to the unrealized gains on oil and gas hedges. The gain was recorded to reflect the estimated fair value of the oil hedge contracts in place through April 2013 for a total of approximately 443,144 Bbls of oil production.

Note 5 Convertible Notes

8% Senior Subordinated Convertible Notes

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

The $9.0 million debt component of the Notes was initially recorded net of debt issuance discount of $9.0 million. The debt issuance discount was amortized to interest expense over the life of the Notes using the effective interest method. The Company recorded $7.4 million and $1.6 million of debt issuance discount amortization during the twelve months ended December 31, 2008 and 2007, respectively.

Additionally, the Company recorded $1.4 million and $300,000 of amortization of deferred debt issuance costs during the twelve months ended December 31, 2008 and 2007, respectively.

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

Effective October 7, 2008, the Company entered into a Warrant Exchange Agreement, dated October 4, 2008, with all of the holders of the stock purchase warrants issued on May 16, 2007 and the placement agent warrants issued on May 18, 2007, to exchange the warrants for an aggregate of 990,000 shares of the Company s common stock, par value $0.001. The warrants were carried on the Company s balance sheet as a current liability at fair value, as determined using level 2 inputs into the Black-Scholes valuation model. The Company recognized a gain of $7,762 related to the exchange of the warrants for shares of its Common Stock.

10.75% Secured Convertible Debentures

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

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

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

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

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

On November 13, 2008, one of the investors, who held a $3.75 million investment in the Debentures, elected to convert, bringing the total outstanding amount on the Debentures to $26.25 million. The Company issued 576,924 shares of our common stock (based on the $6.50 stated conversion rate), 216,541 shares of the Company s common stock related to the interest make-whole provision and paid $893,000 in cash related to accrued interest through the conversion date and for the remaining amount of the interest make-whole. In the Statement of Operations, the line item Interest make-whole premium on conversion of debt equals the make-whole (both the cash and stock portions) of $1,028 plus the unamortized debt issuance costs of $208 at the time of conversion. The total cost to the Company was approximately $1.7 million or $2.05 million less than the outstanding amount of the debt that was converted. There is no gain recognized on the transaction in accordance with current accounting literature. The $2.05 million is booked directly as additional paid in capital, increasing the equity of the Company. On January 16, 2009, the Company retired an additional $750 of the Debentures for $273, bringing the total outstanding on the Debentures to $25.5 million. Deferred debt issuance costs of $2,213 associated with the Convertible Notes are included in assets as of December 31, 2008 and will be amortized to interest expense over the life of the related Debenture. Additionally, the Company recorded $266 of amortization of deferred debt issuance costs during the twelve months ended December 31, 2008, related to the Notes.

Note 6 Senior Bank Facility

Long-term debt included the following:

	December 31, 2008	December 31, 2007
	(in thousands)	
Senior bank credit facility	$ 29,650	$ 8,000

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

As a result of the Company s sale of part of its Piceance Basin properties that closed on October 1, 2007, JPMorgan reduced the borrowing base and the conforming borrowing base on the Amended Credit Facility to $8.0 million. On February 11, 2008, the Company repaid the entire $8.0 million balance outstanding under the Amended Credit Facility, leaving the entire $10 million available under the borrowing base.

On April 2, 2008, the Company again amended its Credit Facility (the Amended Credit Facility) to a $150 million revolving credit facility ($50 million borrowing base). In connection with the privately placed 10.75% Secured Convertible Debenture, the borrowing base on the Company s $150 million revolving credit facility was reduced from $50 million to $32.5 million. On August 1, 2008 the borrowing base was re-determined and increased to $34.5 million. The Company s total available borrowings under the Debentures and the Amended Credit Facility are approximately $55.9 million as of December 31, 2008.

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

The Company borrowed on its Amended Credit Facility during the second quarter of 2008 to partially fund the acquisition of certain oil and gas properties in the Central Kansas Uplift and to repay $6.6 million of the 8% Senior Secured Convertible Notes. With the gross proceeds of the $30 million privately placed 10.75% Secured

Convertible Debentures (see Note 5 above), on June 18, 2008, the Company repaid approximately $28 million on its Amended Credit Facility. During the third quarter of 2008, the Company borrowed a net $3 million on its Amended Credit Facility to fund the exploration and development of its operated properties in the Central Kansas Uplift and non-operated properties in the Piceance Basin and the Teton-Noble AMI.

The balance outstanding at December 31, 2008 was approximately $29.7 million. For the twelve months ended December 31, 2008, 2007 and 2006, cash interest expense with respect to the above credit lines and the Convertible Notes described in Note 5 totaled $2,608, $815 and $0, respectively, and capitalized interest totaled $372, $121 and $0, respectively.

Note 7 Stockholders Equity

Preferred Stock

The Company is authorized to issue up to 25,000,000 shares of $.001 par value preferred stock, the rights and preferences of which are to be determined by the Board of Directors at or prior to the time of issuance. There were no shares of preferred stock outstanding as of December 31, 2008 and 2007.

Common Stock & Warrants

On July 25, 2007, the Company completed a registered direct offering of 964,060 shares of its common stock, at a price of $5.05 per share, to a selected group of institutional investors for gross proceeds of $4.9 million. The offering included 337,421 warrants to purchase 337,421 shares of common stock at an exercise price of $6.06 per share with a term of five years. Offering costs, including underwriter s fees, legal, accounting and other related expenses, totaled $558,000, which includes the issuance of 77,126 warrants to purchase 77,126 shares of common stock to the Company s placement agent in the transaction valued at $190,000.

On April 2, 2008, in conjunction with the purchase of production and reserves related to certain oil and gas producing properties in the Central Kansas Uplift, the Company issued 625,000 warrants to acquire shares of Teton common stock. Each warrant is exercisable at an exercise price of $6.00 per share, and expires on April 1, 2010.

The following table presents the activity for warrants outstanding:

	Shares	Weighted Average Exercise Price
Outstanding December 31, 2005	1,731,764	$ 3.93
Issued		$ 0.00
Exercised	(760,959)	$ 4.65
Forfeited/canceled	(102,986)	$ 5.36
Outstanding December 31, 2006	867,819	$ 3.14
Issued	4,374,547	$ 5.10
Exercised	(1,500)	$ 1.75
Forfeited/canceled		$ 0.00
Outstanding December 31, 2007	5,240,866	$ 4.78
Issued	625,000	$ 6.00
Exercised	(599,468)	$ 3.18
Warrant Exchange Agreement	(3,960,000)	$ 5.00
Forfeited/canceled	(33,947)	$ 1.77
Outstanding December 31, 2008	1,272,451	$ 5.51

Table of Contents

The following table presents the composition of warrants outstanding and exercisable as of December 31, 2008:

Range of Exercise Prices	Number	Weighted Average Remaining Contractual Life (years)
$3.24	232,904	4.0
$6.00	625,000	1.3
$6.06	414,547	3.6
Total warrants outstanding and exercisable	1,272,451	2.5

Derivative Financial Instruments

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 5, on May 16, 2007, the Company entered into a Convertible Note and Warrant financing that was 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. 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 (or tainted warrants) required reclassification to derivative liabilities on the date of the financing. As further discussed in Note 5, on June 28, 2007, the Company amended the Convertible Note agreements 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 estimated fair values from (to) stockholders equity during 2007:

		Year Ended December 31, 2007 (in thousands)
Reclassifications of derivative liabilities from (to) stockholders equity:		
Existing warrants tainted to derivative liabilities	$	4,951
Compound embedded derivative no longer requiring bifurcation		(1,435)
Financing warrants issued to placement agents no longer tainted		(1,128)
Existing warrants no longer tainted to stockholders equity		(5,512)
Net change in stockholders equity	$	(3,124)

Note 8 Stock-Based Compensation

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

Table of Contents

	For the Years Ended December 31,		
	2008	2007	2006
		(in thousands)	
Performance share units employees and directors	$ 2,744	$ 2,421	$ 2,413
Performance-vesting restricted common stock employees and directors	917	278	
LTIP restricted common stock employees and directors		571	487
Stock options employees	9	18	28
Total stock-based compensation expense	3,670	3,288	2,928
Performance share units non-employees		264	211
Restricted common stock non-employees			(158)
Total stock-based compensation expense	$ 3,670	$ 3,552	$ 2,981

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 performance share units, restricted stock units, restricted stock, stock options, stock appreciation rights, and other stock-based awards to employees, directors, consultants and advisors (Participants) as administered by the Compensation Committee of the Board of Directors (the Compensation Committee). Shares issued to participants under this plan are newly issued shares.

LTIP Performance Share Units

The Compensation Committee established a pool (Pool) of Performance Share Units (Units) under the LTIP for 2005 and 2006 and granted Units (each a Grant, collectively Grants) to Participants (each such year in which Units were granted becoming a Grant Year). The Grants vested solely as a result of the Company achieving performance goals established by the Compensation Committee. Each Grant vested in three tranches over a three-year period, and was conditioned on the Participant remaining employed by the Company at each measurement date, which was December 31 of each calendar year.

The Compensation Committee designated annual performance goals for each tranche as Threshold, Base, and Stretch. If the Company achieved the Threshold level of performance, 25% of the Units in that tranche would vest. If the Company achieved the Base level of performance, 50% of the Units in that tranche would vest. If the Company achieved the Stretch level of performance, 100% of the Units in that tranche would vest. If the Threshold performance level was not achieved, no Units in that tranche would vest. Once the performance results had been certified by the Compensation Committee, the vested Units were issued to the Participants as common stock.

The fair value of each Unit was measured based on the market price of the Company s common stock on the date of Grant. Stock-based compensation expense was recognized based upon the number of Units granted to employees and directors that vested each year. During the years ended December 31, 2008, 2007 and 2006, the Company recorded $2.7 million, $2.4 million and $2.4 million, respectively, of stock-based compensation expense applicable to the vesting of Units granted to employees and directors.

Other general and administrative expense was recognized based upon the market value of the Units granted to consultants, advisors and other non-employees that vested each year. During the years ended December 31, 2008, 2007 and 2006, the Company recorded $0, $0.3 million and $0.2 million, respectively, of other general and administrative expense applicable to the vesting of Units granted to non-employees.

On July 26, 2005, the Compensation Committee established a Pool of 800,000 Units for grant (the 2005 Grants). During 2005 and 2006, 895,000 Units were granted to Participants by the Compensation Committee (including Units re-granted out of forfeitures). The 2005 Grants vested in three tranches (20% in 2005, 30% in 2006 and 50% in 2007), provided the goals set forth by the Compensation Committee were met. The performance goals for the 2005 Grants were based upon attaining specific annual or year-end objectives, including: (a) achieving certain levels of oil and gas reserves, (b) achieving a certain level of oil and gas production, (c) achieving a certain level of stock price performance, (d) achieving finding and development costs goals and (e) achieving an overall management efficiency and effectiveness rating. During the years ended December 31, 2007 and 2006, 133,507 and 134,767 Units applicable to the 2005 Grants vested, and the underlying common shares were considered issued and outstanding on those dates.

During 2006, the Compensation Committee initially established a pool of 2,500,000 Units for grant (the 2006 Grants). During 2006, 1,969,250 Units were granted to Participants by the Compensation Committee. The 2006 Grants were to 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 goals were based upon attaining specific annual or year-end objectives, including: (a) increasing the Company s asset base through acquisitions, (b) achieving stock price goals relative to an index of comparable companies stock prices, and (c) achieving an overall management efficiency and effectiveness rating. During the years ended December 31, 2008, 2007 and 2006, 0, 177,619 and 291,750 Units, respectively, applicable to the 2006 Grants vested and the underlying common shares were considered issued and outstanding on those dates. At December 31, 2008, the Compensation Committee of the Board of Directors chose to terminate the 2006 Grants without vesting the final tranche. Further, the employees, officers and directors permanently waived their rights to any December 31, 2008 vesting, or future vesting, of the 2006 Grants.

A summary of the 2005 and 2006 Grant activity is below:

	Unvested 2005 Grants (shares)	Weighted Average Grant Date Market Price	Unvested 2006 Grants (shares)	Weighted Average Grant Date Market Price
Outstanding December 31, 2005	596,000	$4.88		$0.00
Granted	150,000	$5.23	1,969,250	$6.71
Vested	(134,767)	$4.95	(291,750)	$6.71
Forfeited/returned	(256,233)	$4.94	(121,500)	$6.74
Outstanding December 31, 2006	355,000	$4.95	1,556,000	$6.71
Vested, net of shares withheld for payroll taxes	(133,507)	$4.91	(177,619)	$6.74
Forfeited/returned	(221,493)	$4.98	(674,881)	$6.68
Outstanding December 31, 2007		$	703,500	$6.72
Vested, net of shares withheld for payroll taxes				
Forfeited/returned/canceled			(703,500)	$6.72
Outstanding December 31, 2008		$		$

During 2007, 540,000 shares were granted to Participants by the Compensation Committee (the 2007 Grants). The 2007 Grants were to vest in three tranches (20% at June 30, 2008, 30% at June 30, 2009 and 50% at June 30, 2010), provided the goals set forth by the Compensation Committee were met. The performance goals for the 2007 Grants were based upon attaining specific annual or period-end objectives, including: (a) achieving certain levels of oil and gas reserves, (b) achieving a certain level of oil and gas production, and (c) achieving an overall management efficiency and effectiveness rating. The first tranche of the 2007 Grants was vested at June 30, 2008 and paid to Participants in the third quarter 2008. However, the Compensation Committee of the Board of Directors chose to terminate the 2007 Grants without vesting the final two tranches. Further, the employees, officers and directors permanently waived their rights to any future vesting of the 2007 Grants.

Table of Contents

A summary of the 2007 Grant activity is below:

	Unvested 2007 Grants (shares)	Weighted Average Grant Date Market Price
Outstanding December 31, 2006		
Granted in 2007	540,000	$5.15
Outstanding December 31, 2007	540,000	$5.15
Vested, net of shares withheld for payroll taxes	(105,071)	$5.15
Forfeited/returned/canceled	(434,929)	$5.15
Outstanding December 31, 2008		

During 2008, the Compensation Committee awarded a total of up to 2,960,400 Performance Share Units in the aggregate to Participants. The period being measured for the Performance Share Units was January 1, 2008 through December 31, 2010. The performance measure under this Award was based on increases in the Company s net asset value per share. The grants were to vest at 20%, 30% and 50% when the net asset value per share of the Company increased by 40%, 100% and 200%, respectively, from a base level set by the Compensation Committee as of December 31, 2007. On August 4, 2008, the Compensation Committee certified the results of the performance milestone for Tranche 1 (the achievement of a 40% increase in net asset value per share) of the 2008 grants. As a result of such certification, an aggregate of 522,414 shares of common stock vested and 370,667 shares net of taxes withheld were issued, as of such date.

A summary of the 2008 Grant activity is below:

	Unvested 2008 Grants (shares)	Weighted Average Grant Date Market Price
Outstanding December 31, 2007		$0.00
Granted in 2008	2,960,400	$4.83
Vested, net of shares withheld for payroll taxes	(370,667)	$4.76
Forfeited/returned/canceled	(183,333)	$4.84
Outstanding December 31, 2008	2,406,400	$4.85

Based on current economic conditions, current commodity prices and the current state of the capital markets, it is improbably that any future vesting of the 2008 Grants will occur prior to its scheduled termination at December 31, 2010.

LTIP Restricted Common Stock

LTIP restricted common stock is granted to Participants pursuant to the Company s LTIP and shares generally vest over three years based solely on service. Compensation expense is recorded at fair value based on the market price of the Company s common stock at the date of grant and is recognized over the related service period. During the years ended December 31, 2008, 2007 and 2006 the Company recorded $0.9 million, $0.5 million and $0.5 million, respectively of stock-based compensation expense applicable to LTIP restricted stock grants.

Table of Contents

A summary of LTIP restricted common stock activity is below:

	Unvested LTIP - Restricted Common Stock (shares)	Weighted Average Grant Date Market Price
Outstanding December 31, 2005	195,000	$ 6.06
Granted	69,000	$ 5.84
Vested	(70,001)	$ 6.08
Outstanding December 31, 2006	193,999	$ 5.98
Granted	57,400	$ 5.07
Vested	(96,335)	$ 5.99
Forfeited/canceled	(33,332)	$ 6.18
Outstanding December 31, 2007	121,732	$ 5.49
Granted	389,550	$ 4.97
Vested	(97,549)	$ 5.58
Forfeited/canceled	(94,001)	$ 5.22
Outstanding December 31, 2008	319,732	$ 4.98

Restricted Common Stock

Effective March 31, 2006, in connection with the resignation of the Company s former contract Chief Financial Officer, 50,000 shares of restricted common stock were returned to the Company as an agreed-upon reduction in service fees charged. The return of such shares was recorded as a reduction in accounting fees included in general and administrative expenses totaling $158,000.

Stock Options

On March 19, 2003, the Company s shareholders approved an employee stock option plan (the 2003 Plan) authorizing a pool of 3,000,000 options available to grant. On June 28, 2005, the 2003 Plan was terminated upon shareholder approval of the LTIP; however options granted under the 2003 Plan remain outstanding until exercised, forfeited or expired pursuant to the terms of each grant.

During 2003 and 2004, 2,993,037 options were granted with no vesting requirements and expiration dates over various periods up to ten years from the date of grant.

During 2005, the Company granted 45,000 stock options under the 2003 Plan to certain employees. These options have ten year terms and vest over a three-year period, assuming the employees remain in the Company s employ.

In accordance SFAS No. 123R, effective January 1, 2006, the Company began recognizing compensation expense for unvested stock options over the period that the stock options vest. During the years ended December 31, 2008, 2007 and 2006, the Company recognized $9,000, $18,000 and $28,000, respectively, of stock-based compensation expense applicable to stock option vesting as a component of general and administrative expense. As of December 31, 2008, there were no unvested stock options outstanding, and 100% of the compensation expense had been recognized.

Table of Contents

A summary of stock option activity for the three years ended December 31, 2008 is below:

	Stock Options (shares)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding December 31, 2005	2,875,334	$ 3.54	5.9	$ 6,788
Exercised	(770,039)	3.50		1,648
Forfeited/expired	(16,750)	3.11		
Outstanding December 31, 2006	2,088,545	3.56	5.4	2,867
Exercised	(672,701)	3.57		935
Outstanding December 31, 2007	1,415,844	3.55	5.8	1,916
Exercised		0.00		
Forfeited/expired		0.00		
Outstanding December 31, 2008	1,415,844	$ 3.55	4.8	$
Exercisable at December 31, 2006	2,075,212	$ 3.56	5.4	$ 2,842
Exercisable at December 31, 2007	1,415,844	$ 3.55	5.8	$ 1,904
Exercisable at December 31, 2008	1,415,844	$ 3.55	4.8	$

Note 9 Benefit Plans

During 2005, the Company established a SIMPLE IRA plan which provides retirement savings options for all eligible employees. The Company makes a matching contribution based on the participants eligible wages. The Company made matching contributions of approximately $79, $35 and $23 during the years ended December 31, 2008, 2007 and 2006, respectively.

Note 10 Income Taxes

For each of the three years in the period ended December 31, 2008, the current and deferred provisions for income taxes were zero.

Total income tax expense differed from the amounts computed by applying the federal statutory income tax rate of 35% to income (loss) before income taxes as a result of the following items:

	Year Ended December 31, 2008	2007	2006
		(in thousands)	
Federal statutory income tax provision (benefit)	$ (4,960)	$ 832	$ (2,004)
State income tax provision (benefit), net of federal income tax provision/benefit	(417)	77	(171)
Loss on derivative contract liabilities	(2,950)	991	
Debt issuance discount amortization	2,801	619	16

Other	551	129	
Change in valuation allowance	4,975	(2,648)	2,159
Income tax expense	$	$	$

The tax effects of temporary differences that give rise to significant components of the Company s deferred tax assets and liabilities are as follows:

Table of Contents

	December 31, 2008	2007
	(in thousands)	
Current deferred tax assets (liabilities):		
Other receivables	$ (83)	$
Accounts payable and accrued liabilities		
Oil and gas derivatives	(1,982)	173
Debt issuance costs	(221)	(221)
Valuation allowance		
Net current deferred tax assets (liabilities)	(2,286)	(48)
Non-current deferred tax assets (liabilities):		
Stock-based compensation		1,108
Debt issuance costs	20	
Oil and gas properties	(3,758)	(4,481)
Oil and gas derivatives	(2,656)	
Net operating loss	22,598	12,358
Valuation allowance	(13,918)	(8,937)
Net non-current deferred tax assets (liabilities)	2,286	48
Net deferred tax assets (liabilities)	$	$

At December 31, 2008, the Company had net operating loss carryforwards (NOLs), for federal income tax purposes, of approximately $59.5 million. These NOLs, if not utilized to reduce taxable income in future periods, will expire in various amounts from 2018 through 2028. Approximately $2.2 million of such NOL s are subject to limitation under Section 382 of the Internal Revenue Code, all of which will free up in 2009. During 2008, the Company had no deductions from the exercise of nonqualified stock options. The Company has established a valuation allowance for deferred taxes equal to its entire net deferred tax assets as management currently believes that it is more likely than not that these losses will not be utilized.

On January 1, 2007, the Company adopted the provisions of FIN 48, which requires that the Company recognize in its consolidated financial statements only those tax positions that are more-likely-than-not of being sustained as of the adoption date, based on the technical merits of the position. As a result of the implementation of FIN 48, the Company performed a comprehensive review of its material tax positions in accordance with recognition and measurement standards established by FIN 48.

The Company is subject to the following material taxing jurisdictions: U.S., Colorado, Nebraska and Kansas beginning in 2008. The tax years that remain open to examination by the Internal Revenue Service are 2005 through 2008. The tax years that remain open to examination by the Colorado Department of Revenue and the Nebraska Department of Revenue are 2004 through 2008. The Company s policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. The Company has no accrued interest or penalties related to uncertain tax positions as of January 1, 2008 or December 31, 2008.

Table of Contents

Note 11 Commitments and Contingencies

To mitigate a portion of the potential exposure to adverse market changes in the prices of oil and natural gas, the Company has entered into various derivative contracts. The outstanding commodity hedges as of December 31, 2008 are summarized below:

Type of Contract	Remaining Volume	Fixed Price per Barrel	Price Index (1)	Remaining Period
Oil Costless Collar	143,545	$90.00 Floor/$104.00 Ceiling	WTI	01/01/09-12/31/09
Oil Costless Collar	106,876	$90.00 Floor/$104.00 Ceiling	WTI	01/01/10-12/31/10
Oil Costless Collar	87,920	$90.00 Floor/$104.00 Ceiling	WTI	01/01/11-12/31/11
Oil Costless Collar	79,611	$90.00 Floor/$104.00 Ceiling	WTI	01/01/12-12/31/12
Oil Costless Collar	25,192	$90.00 Floor/$104.00 Ceiling	WTI	01/01/13-04/30/13
Total Bbl	443,144			

(1) Fixed price is per Bbl. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

On April 30, 2008, the Company entered into a lease agreement for new office space in Denver for a period of 69 months, which started on November 1, 2008. Rental payments, before expenses, under the lease were $32,509 during 2008. After November 1, 2008, the Company had no further obligations under its previous lease agreement.

The following outlines the Company s contractual commitments that are not recorded on the Company s consolidated balance sheet:

	For the Years Ending December 31,			
	2009	2010	Thereafter	Total
	(in thousands)			
Operating lease for office space	$ 372	$ 416	$ 1,548	$ 2,336

Rent expense for the Denver office was approximately $212,000, $120,000 and $97,000 in 2008, 2007 and 2006, respectively.

Note 12 Supplemental Oil and Gas Disclosures

Capitalized Costs Relating to Oil and Gas Producing Activities

The following reflects the Company s capitalized costs associated with oil and gas producing activities:

	For the Years Ended December 31,		
	2008	2007	2006
	(in thousands)		
Oil and gas properties:			
Proved	$ 94,682	$ 35,861	$ 259
Unproved	22,005	13,411	13,959
Facilities in progress			1,364
Wells in progress	7,702	3,230	8,492

Subtotal	124,389	52,502	24,074
Accumulated depletion and depreciation	(17,902)	(3,535)	(1,833)
Net capitalized costs	$ 106,487	$ 48,967	$ 22,241

Table of Contents

Costs Incurred in Oil and Gas Property Acquisitions, Exploration and Development Activities

Costs incurred in property acquisitions, exploration and development activities (including asset retirement costs) are as follows:

	For the Years Ended December 31, 2008	2007	2006
		(in thousands)	
Property acquisition costs unproved properties	$ 8,609	$ 2,465	$ 3,323
Property acquisition costs proved properties	32,218	4,342	
Development costs	30,826	32,900	17,163
Exploration costs	3,113	2,712	1,823

The following table reflects the net changes in capitalized exploratory well costs and does not include amounts that were capitalized and either subsequently expensed or reclassified to proved properties or producing facilities in the same period. No exploratory well costs have been capitalized for a period greater than one year from the completion of exploratory drilling.

	2008	2007	2006
Beginning balance at January 1, 2008	$	$ 1,375	$ 2,106
Additions to capitalized exploratory well costs pending the determination of proved reserves	530		1,375
Reclassifications to wells, facilities and equipment based on the determination of proved reserves		(1,375)	(2,106)
Capitalized exploratory well costs charged to expense			
Ending balance at December 31, 2008	$ 530	$	$ 1,375

Results of Operations from Oil and Gas Producing Activities

Results of operations from oil and gas producing activities (excluding general and administrative expense) are as follows:

	For the Years Ended December 31, 2008	2007	2006
		(in thousands)	
Oil and gas sales	$ 28,469	$ 6,253	$ 4,022
Operating expenses:			
Lease operating expense	4,247	705	325
Workover expense	234		
Transportation costs	1,827	652	493
Production taxes	1,932	412	251
Exploration expense	4,831	1,847	448
Depletion, depreciation and accretion expense	14,396	3,751	1,697
Impairment expense	14,260		
Total operating expenses	41,727	7,367	3,214
Operating (loss) income	$ (13,258)	$ (1,114)	$ 808

Oil and Gas Reserves (Unaudited)

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. The reserve information presented below was prepared by Netherland Sewell & Associates, Inc., independent petroleum engineers. The Company did not have any oil reserves at December 31, 2006.

Table of Contents

Estimated net quantities

	For the Years Ended December 31,				
	2008		2007		2006
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Gas (MMcf)
Proved reserves, beginning of year	129	13,308		7,093	4,009
Revisions of estimates	(3)	(4,202)	40	4,018	3,821
Extensions and discoveries	50	9,124	43	14,505	
Purchase of reserves in place	1,574	309	87	574	
Sales of reserves in place			(24)	(11,754)	
Production	(192)	(1,658)	(17)	(1,128)	(737)
Proved reserves, end of year	1,558	16,881	129	13,308	7,093
Proved developed reserves, beginning of year	112	7,930		4,927	853
Proved developed reserves, end of year	1,444	9,485	112	7,930	4,927

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

SFAS No. 69 Disclosures about Oil and Gas Producing Activities (SFAS No. 69) prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to the estimated quantities of oil and gas to be produced. Estimated future income taxes are computed using current statutory income tax rates for those countries where production occurs. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and as such do not necessarily reflect the Company s expectations for actual revenues to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process.

The resulting standardized measure is less than the net book value of the Company s proved properties as presented on the Consolidated Balance Sheet at December 31, 2008. However, the estimated undiscounted future net cash flows approximate the net book value. As noted under the caption Impairment of Long-lived Assets in Note 1 above, the Company has evaluated the proved properties and recorded any impairment that is necessary at December 31, 2008.

Table of Contents

The following summarizes the standardized measure and sets forth the Company s estimated future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in SFAS No. 69:

	As of December 31,		
	2008	2007	2006
Future cash inflows	$ 136,985	$ 88,297	$ 29,167
Future production costs	(61,747)	(22,782)	(10,066)
Future development costs	(23,030)	(13,708)	(3,419)
Future income taxes			
Future net cash flows	52,208	51,807	15,682
10% annual discount	(23,975)	(23,815)	(6,977)
Standardized measure of Discounted future net cash flows	$ 28,233	$ 27,992	$ 8,705

The following are the principal sources of changes in the standardized measure of estimated discounted future net cash flows:

	As of December 31,		
	2008	2007	2006
Standard measure, as of January 1,	$ 27,992	$ 8,705	$ 8,716
Sales of oil and gas produced, net of production costs	(20,451)	(4,484)	(2,953)
Net change in prices and production costs related to future production	(5,716)	2,172	(10,798)
Extensions and discoveries	5,251	31,190	
Development costs incurred during the year	29,655	2,519	
Changes in estimated future development costs	(25,963)	400	2,481
Sales of reserves in place		(24,465)	
Purchases of reserves in place	20,838	5,272	
Revisions of previous quantity estimates	(5,433)	8,433	10,387
Accretion of discount	2,799	871	872
Net change in income taxes			
Changes in timing and other	(739)	(2,621)	
Standardized measure, as of December 31,	$ 28,233	$ 27,992	$ 8,705

Table of Contents

Note 13 Selected Quarterly Information (Unaudited)

The following represents selected quarterly financial information:

	For the Quarter Ended			
	March 31,	June 30,	Sept 30,	Dec 31,
	(In thousands, except per share amounts)			
2008				
Total operating revenues	$ 3,640	$ 10,121	$ 9,765	$ 4,943
Operating income (loss)	$(3,378)	$ (700)	$ 6,423	$(25,079)
Net income (loss)	$(8,223)	$(30,028)	$19,304	$ 4,774
Income (loss) per common share basic	$ (0.46)	$ (1.40)	$ 0.88	$ 0.20
Income (loss) per common share fully diluted (1)	$ (0.46)	$ (1.40)	$ 0.74	$ 0.20
2007				
Total operating revenues (2) (3)	$ 1,198	$ 990	$ 1,317	$ 20,189
Operating income (loss) (3)	$(1,779)	$ (2,404)	$ (2,564)	$ 14,012
Net income (loss) (3)	$(1,801)	$ (7,246)	$ (951)	$ 12,375
Basic and diluted loss per common share	$ (0.12)	$ (0.45)	$ (0.06)	$ 0.72
Income (loss) per common share diluted	$ (0.12)	$ (0.45)	$ (0.06)	$ 0.67

(1) Since there was net income in some quarters but a net loss for the year, the Income (loss) per common share fully diluted for the individual quarters of 2008 do not total the Loss per common share fully diluted for the entire year as shown in the financial statements.

(2) Quarterly operating revenues for the quarterly periods ended March 31, June 30, September 30

and December 31, 2007 have been reclassified to conform to presentation for the quarters ended March 31, June 30, September 30 and December 31, 2008. The total operating revenues includes gross revenues before gathering and transportation expenses which are now included in transportation expense in the Consolidated Statement of Operations.

(3) The gain on sale of oil and gas properties of $17,441 is included in the total operating revenues, operating income (loss) and net income (loss) amounts for the quarter ended December 31, 2007.

Table of Contents

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Management necessarily applied its judgment in assessing the costs and benefits of such controls and procedures, which, by their nature, can provide only reasonable assurance regarding management s control objectives.

With the participation of management, our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the design and operation of our disclosure controls and procedures at the conclusion of the period ended December 31, 2008. Based upon this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective in ensuring that material information required to be disclosed is included in the reports that we file with the Securities and Exchange Commission.

(b) Management s Report on Internal Control over Financial Reporting

Our Company management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company s internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements.

Because of the inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control Integrated Framework. Management s assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of these controls.

Based on this assessment, management has concluded that as of December 31, 2008, our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Table of Contents

The Company s independent registered public accounting firm, Ehrhardt Keefe Steiner & Hottman PC (EKSH), has issued a report on the effectiveness of the Company s internal controls over financial reporting as of December 31, 2008, and EKSH s report is included under Item 8 of this Annual Report on Form 10-K.

(c) Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during our fiscal quarter ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

On December 4, 2008, the Compensation Committee of the Board of Directors approved certain amendments to the employment agreements with the named executive officers of the Company. The changes, which were made to ensure the continued employment of key individuals during turbulent economic times, were disclosed in the Company s Form 8-K, filed on December 10, 2008. The definitive employment agreements are filed as exhibits 10.23 through 10.27 to this Form 10-K.

PART III

Pursuant to instruction G(3) to Form 10-K, the following Items 10,11,12,13 and 14 are incorporated by reference to the information provided in the Company s definitive proxy statement for the 2009 annual meeting of stockholders to be filed within 120 days from December 31, 2008.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

Exhibits.

Exhibit No.	Description
3.1.1	Certificate of Incorporation of EQ Resources Ltd incorporated by reference to Exhibit 2.1.1 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.2	Certificate of Domestication of EQ Resources Ltd incorporated by reference to Exhibit 2.1.2 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.3	Articles of Merger of EQ Resources Ltd. and American-Tyumen Exploration Company incorporated by reference to Exhibit 2.1.3 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.4	Certificate of Amendment to Certificate of Incorporation of Teton Petroleum Company incorporated by reference to Exhibit 2.1.4 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.5	Certificate of Amendment to Certificate of Incorporation of Teton Petroleum Company incorporated by reference to Exhibit 2.1.5 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.6	Certificate of Amendment to Certificate of Incorporation, dated June 28, 2005, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 15, 2005.
3.2	Bylaws, as amended, of Teton Petroleum Company incorporated by reference to Exhibit 3.2 of Teton s Form 10-QSB, filed August 20, 2002.
4.1	Certificate of Designation for Series A Convertible Preferred Stock, incorporated by reference to Exhibit 3.1.6 of Teton s Form SB-2 (File No. 333-112229), filed January 27, 2004.
4.2	Certificate of Designations, Preferences and Rights of the Terms of the Series C Preferred Stock, incorporated by reference to Exhibit 3.1 of Teton s 8-K filed on June 8, 2005.
4.3	Secured Subordinated Convertible Debenture Indenture dated September 19, 2008 among Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on September 23, 2008).
4.4	Form of 10.75% Secured Convertible Debenture dated June 18, 2008 issued by Teton Energy Corporation (incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.5	Form of Global 10.75% Secured Subordinated Convertible Debenture (included in Exhibit 4.3).

4.6	Form of Securities Purchase Agreement dated June 9, 2008, entered into by and between Teton Energy Corporation and the investors (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.7	Letter Agreement dated September 19, 2008 amending and supplementing the Securities Purchase Agreement dated June 9, 2008 (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on September 23, 2008).

Table of Contents

Exhibit No.	Description
4.8	Form of Registration Rights Agreement (incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.9	Subordinated Guaranty and Pledge Agreement dated June 18, 2008, entered into by and between Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and Whitebox Advisors LLC (incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.10	Form of Amended and Restated Subordinated Guaranty and Pledge Agreement dated September 19, 2008 (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on September 23, 2008).
4.11	Form of Intercreditor and Subordination Agreement dated June 9, 2008, entered into by and between, Teton Energy Corporation, JPMorgan Chase Bank, N.A. as administrative agent and the representative for the subordinated holders (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.12	Rights Agreement between Teton and Computershare Investors Services, LLC, dated June 3, 2005, incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed on June 8, 2005.
4.13	Form of Senior Subordinated Convertible Note in connection with Teton s May 2007 financing, incorporated by reference to Exhibit 4.1 of Teton s Form 10-Q filed on August 14, 2007.
4.14	Form of Common Stock Purchase Warrant issued to investors in connection with Teton s May 2007 financing, incorporated by reference to Exhibit 4.2 of Teton s Form 10-Q filed on August 14, 2007.
4.15	Form of Common Stock Purchase Warrant issued to investors and placement agents in connection with Teton s July 2007 financing, incorporated by reference to Exhibit 4.3 of Teton s Form 10-Q filed on August 14, 2007.
10.1	International Swap Dealers Association, Inc. Master Agreement, dated October 24, 2006, between BNP Paribas and Teton, incorporated by reference to Exhibit 10.18 of Teton s Form 10-K filed March 19, 2007.
10.2	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, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 14, 2007.
10.3	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, incorporated by reference to Exhibit 10.2 of Teton s Form 10-Q filed on August 14, 2007.
10.4	Form of 2005 Long-Term Incentive Plan 2005 Performance Share Unit Award Agreement, Employees and Directors, incorporated by reference to Exhibit 10.5 of Teton s Form 10-Q filed November 14, 2005.

10.5	Form of 2005 Long-Term Incentive Plan 2005 Performance Share Unit Award Agreement, Patrick A. Quinn, incorporated by reference to Exhibit 10.6 of Teton s Form 10-Q filed November 14, 2005.
10.6	Form of 2005 Long Term Incentive Plan Performance-Based Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on November 13, 2007.

Table of Contents

Exhibit No.	Description
10.7	Amended and Restated Credit Agreement, dated as of August 9, 2007, between and among Teton, as Borrowers, each of the lenders party thereto, and JPMorgan Chase Bank, NA, as Administrative Agent for the lenders, incorporated by reference to Exhibit 10.1 to Teton s Form 8-K, filed on August 10, 2007.
10.8	Amended and Restated Guaranty and Pledge Agreement, dated as of August 9, 2007, made by Teton, in favor of JPMorgan Chase Bank, NA, incorporated by reference to Exhibit 10.2 to Teton s Form 8-K, filed on August 10, 2007.
10.9	Asset Exchange Agreement dated September 26, 2007, between Teton Energy Corporation, Teton Piceance LLC, a wholly owned subsidiary of Teton Energy Corporation and Delta Petroleum Corporation, incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed October 2, 2007.
10.10	Placement Agent Agreement, dated as of May 11, 2007, between Teton and Commonwealth Associates, LP, incorporated by reference to Exhibit 10.3 of Teton s Form 10-Q filed on August 14, 2007.
10.11	Placement Agency Agreement dated as of July 19, 2007, between Teton, Commonwealth Associates, LP and Ferris, Baker Watts, Incorporated, incorporated by reference to Exhibit 10.4 to Teton s Quarterly Report on Form 10-Q filed August 14, 2007.
10.12	Form of Subscription Agreement in connection with Teton s May 2007 financing. incorporated by reference to Exhibit 10.2 to Teton s Registration Statement on Form S-3/A (File No. 333-145164), filed September 5, 2007.
10.13	Advisory Services Agreement dated as of July 1, 2007, between Teton and Commonwealth Associates, L.P., incorporated by reference to Exhibit 10.4 to Teton s Registration Statement on Form S-3/A (File No. 333-145164), filed September 18, 2007.
10.14	Purchase, Sale and Exploration Agreement dated March 24, 2008, entered into on March 28, 2008 by and between, Teton Energy Corporation and Shelby Resources LLC, incorporate by reference to Exhibit 10.1 of Teton s Form 8-K filed April 3, 2008.
10.15	Form of Registration Rights Agreement in connection with the issuances of the shares of Common Stock and the Warrants, in connection with the Purchase, Sale and Exploration Agreement dated March 24, 2008 by and between, Teton Energy Corporation and Shelby Resources LLC, incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed April 3, 2008.
10.16	Form of Teton Energy Corporation Common Stock Purchase Warrant issued in connection with the Purchase, Sale and Exploration Agreement dated March 24, 2008 by and between, Teton Energy Corporation and Shelby Resources LLC, incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed April 3, 2008.
10.17	Second Amended and Restated Credit Agreement dated as of April 2, 2008 among Teton Energy Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto, incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed on April 3, 2008.

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

Table of Contents

Exhibit No.	Description
10.20	Employment Agreement, dated December 4, 2008, between Dominic J. Bazile, II and Teton Energy Corporation, filed herewith.
10.21	Employment Agreement, dated December 4, 2008, between Lonnie Brock and Teton Energy Corporation, filed herewith.
10.22	Employment Agreement, dated December 4, 2008, between Rich Bosher and Teton Energy Corporation, filed herewith.
10.23	Employment Agreement, dated December 4, 2008, between Steve Godfrey and Teton Energy Corporation, filed herewith.
14	Code of Ethics and Business Conduct, incorporated by reference to Exhibit 14.1 of Teton s 10-K filed on March 31, 2005.
21.1	List of Subsidiaries, filed herewith.
23.1	Consent of independent registered accounting firm, filed herewith.
23.2	Consent of Independent Petroleum Engineers and Geologists, filed herewith.
31.1	Certification by Chief Executive Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
31.2	Certification by Chief Financial Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
32	Certification by Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, filed herewith.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TETON ENERGY CORPORATION

By: /s/ Karl F. Arleth
Karl. F. Arleth,
Chief Executive Officer
Dated: March 5, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ James J. Woodcock James J. Woodcock	Chairman and Director	March 5, 2009
/s/ Karl F. Arleth Karl F. Arleth	President, CEO (principal executive officer) and Director	March 5, 2009
/s/ Thomas F. Conroy Thomas F. Conroy	Director	March 5, 2009
/s/ John T. Connor John T. Connor	Director	March 5, 2009
/s/ Bill I. Pennington Bill I. Pennington	Director	March 5, 2009
/s/ Robert Bailey Robert Bailey	Director	March 5, 2009
/s/ Dominic J. Bazile II. Dominic J. Bazile II	Executive Vice President, COO and Director	March 5, 2009
/s/ Lonnie R. Brock Lonnie R. Brock	Chief Financial Officer (principal financial and accounting officer)	March 5, 2009

Table of Contents

Exhibits.

Exhibit No.	Description
3.1.1	Certificate of Incorporation of EQ Resources Ltd incorporated by reference to Exhibit 2.1.1 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.2	Certificate of Domestication of EQ Resources Ltd incorporated by reference to Exhibit 2.1.2 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.3	Articles of Merger of EQ Resources Ltd. and American-Tyumen Exploration Company incorporated by reference to Exhibit 2.1.3 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.4	Certificate of Amendment to the Certificate of Incorporation of Teton Petroleum Company incorporated by reference to Exhibit 2.1.4 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.5	Certificate of Amendment to the Certificate of Incorporation of Teton Petroleum Company incorporated by reference to Exhibit 2.1.5 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.6	Certificate of Amendment to Certificate of Incorporation, dated June 28, 2005, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 15, 2005.
3.2	Bylaws, as amended, of Teton Petroleum Company incorporated by reference to Exhibit 3.2 of Teton s Form 10-QSB, filed August 20, 2002.
4.1	Certificate of Designation for Series A Convertible Preferred Stock, incorporated by reference to Exhibit 3.1.6 of Teton s Form SB-2 (File No. 333-112229), filed January 27, 2004.
4.2	Certificate of Designations, Preferences and Rights of the Terms of the Series C Preferred Stock, incorporated by reference to Exhibit 3.1 of Teton s 8-K filed on June 8, 2005.
4.3	Secured Subordinated Convertible Debenture Indenture dated September 19, 2008 among Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on September 23, 2008).
4.4	Form of 10.75% Secured Convertible Debenture dated June 18, 2008 issued by Teton Energy Corporation (incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.5	Form of Global 10.75% Secured Subordinated Convertible Debenture (included in Exhibit 4.3).
4.6	Form of Securities Purchase Agreement dated June 9, 2008, entered into by and between Teton Energy Corporation and the investors (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on June 19, 2008).

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

Table of Contents

Exhibit No.	Description
4.9	Subordinated Guaranty and Pledge Agreement dated June 18, 2008, entered into by and between Teton Energy Corporation, Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC, Teton Big Horn LLC, Teton DJCO LLC and Whitebox Advisors LLC (incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.10	Form of Amended and Restated Subordinated Guaranty and Pledge Agreement dated September 19, 2008 (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on September 23, 2008).
4.11	Form of Intercreditor and Subordination Agreement dated June 9, 2008, entered into by and between, Teton Energy Corporation, JPMorgan Chase Bank, N.A. as administrative agent and the representative for the subordinated holders (incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed with the SEC on June 19, 2008).
4.12	Rights Agreement between Teton and Computershare Investors Services, LLC, dated June 3, 2005, incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed on June 8, 2005.
4.13	Form of Senior Subordinated Convertible Note in connection with Teton s May 2007 financing, incorporated by reference to Exhibit 4.1 of Teton s Form 10-Q filed on August 14, 2007.
4.14	Form of Common Stock Purchase Warrant issued to investors in connection with Teton s May 2007 financing, incorporated by reference to Exhibit 4.2 of Teton s Form 10-Q filed on August 14, 2007.
4.15	Form of Common Stock Purchase Warrant issued to investors and placement agents in connection with Teton s July 2007 financing, incorporated by reference to Exhibit 4.3 of Teton s Form 10-Q filed on August 14, 2007.
10.1	International Swap Dealers Association, Inc. Master Agreement, dated October 24, 2006, between BNP Paribas and Teton, incorporated by reference to Exhibit 10.18 of Teton s Form 10-K filed March 19, 2007.
10.2	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, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 14, 2007.
10.3	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, incorporated by reference to Exhibit 10.2 of Teton s Form 10-Q filed on August 14, 2007.
10.4	Form of 2005 Long-Term Incentive Plan 2005 Performance Share Unit Award Agreement, Employees and Directors, incorporated by reference to Exhibit 10.5 of Teton s Form 10-Q filed November 14, 2005.
10.5	Form of 2005 Long-Term Incentive Plan 2005 Performance Share Unit Award Agreement, Patrick A. Quinn, incorporated by reference to Exhibit 10.6 of Teton s Form 10-Q filed November 14, 2005.

10.6	Form of 2005 Long Term Incentive Plan Performance-Based Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on November 13, 2007.
10.7	Amended and Restated Credit Agreement, dated as of August 9, 2007, between and among Teton, as Borrowers, each of the lenders party thereto, and JPMorgan Chase Bank, NA, as Administrative Agent for the lenders, incorporated by reference to Exhibit 10.1 to Teton s Form 8-K, filed on August 10, 2007.

Table of Contents

Exhibit No.	Description
10.8	Amended and Restated Guaranty and Pledge Agreement, dated as of August 9, 2007, made by Teton, in favor of JPMorgan Chase Bank, NA, incorporated by reference to Exhibit 10.2 to Teton s Form 8-K, filed on August 10, 2007.
10.9	Asset Exchange Agreement dated September 26, 2007, between Teton Energy Corporation, Teton Piceance LLC, a wholly owned subsidiary of Teton Energy Corporation and Delta Petroleum Corporation, incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed October 2, 2007.
10.10	Placement Agent Agreement, dated as of May 11, 2007, between Teton and Commonwealth Associates, LP, incorporated by reference to Exhibit 10.3 of Teton s Form 10-Q filed on August 14, 2007.
10.11	Placement Agency Agreement dated as of July 19, 2007, between Teton, Commonwealth Associates, LP and Ferris, Baker Watts, Incorporated, incorporated by reference to Exhibit 10.4 to Teton s Quarterly Report on Form 10-Q filed August 14, 2007.
10.12	Form of Subscription Agreement in connection with Teton s May 25, 2007 financing. incorporated by reference to Exhibit 10.2 to Teton s Registration Statement on Form S-3/A (File No. 333-145164), filed September 5, 2007.
10.13	Advisory Services Agreement dated as of July 1, 2007, between Teton and Commonwealth Associates, L.P., incorporated by reference to Exhibit 10.4 to Teton s Registration Statement on Form S-3/A (File No. 333-145164), filed September 18, 2007.
10.14	Purchase, Sale and Exploration Agreement dated March 24, 2008, entered into on March 28, 2008 by and between, Teton Energy Corporation and Shelby Resources LLC, incorporate by reference to Exhibit 10.1 of Teton s Form 8-K filed April 3, 2008.
10.15	Form of Registration Rights Agreement in connection with the issuances of the shares of Common Stock and the Warrants, in connection with the Purchase, Sale and Exploration Agreement dated March 24, 2008 by and between, Teton Energy Corporation and Shelby Resources LLC, incorporated by reference to Exhibit 10.2 of Teton s Form 8-K filed April 3, 2008.
10.16	Form of Teton Energy Corporation Common Stock Purchase Warrant issued in connection with the Purchase, Sale and Exploration Agreement dated March 24, 2008 by and between, Teton Energy Corporation and Shelby Resources LLC, incorporated by reference to Exhibit 10.3 of Teton s Form 8-K filed April 3, 2008.
10.17	Second Amended and Restated Credit Agreement dated as of April 2, 2008 among Teton Energy Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto, incorporated by reference to Exhibit 10.4 of Teton s Form 8-K filed on April 3, 2008.
10.18	Warrant Exchange Agreement by and between Teton Energy Corporation and the Investors, dated October 4, 2008 and fully executed on October 7, 2008 (incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed with the SEC on October 14, 2008).

10.19	Employment Agreement, dated December 4, 2008, between Karl F. Arleth and Teton Energy Corporation, filed herewith.
10.20	Employment Agreement, dated December 4, 2008, between Dominic J. Bazile, II and Teton Energy Corporation, filed herewith.
10.21	Employment Agreement, dated December 4, 2008, between Lonnie Brock and Teton Energy Corporation, filed herewith.
10.22	Employment Agreement, dated December 4, 2008, between Rich Bosher and Teton Energy Corporation, filed herewith.

Table of Contents

Exhibit No.	Description
10.23	Employment Agreement, dated December 4, 2008, between Steve Godfrey and Teton Energy Corporation, filed herewith.
14	Code of Ethics and Business Conduct, incorporated by reference to Exhibit 14.1 of Teton s 10-K filed on March 31, 2005.
21.1	List of Subsidiaries, filed herewith.
23.1	Consent of independent registered accounting firm, filed herewith.
23.2	Consent of Independent Petroleum Engineers and Geologists, filed herewith.
31.1	Certification by Chief Executive Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
31.2	Certification by Chief Financial Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
32	Certification by Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, filed herewith.