

TETON ENERGY CORP
Form 10-K
March 05, 2009

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**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
(State or other jurisdiction of incorporation
or organization)

84-1482290
(IRS Employer
Identification No.)

**600 17th Street, Suite 1600 North
Denver, Colorado**
(Address of principal executive offices)

80202
(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 No

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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 No

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 No

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.

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

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

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
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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.

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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

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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

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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

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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

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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 MMcf (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 MMcf (10 MBbl of oil and 10.7 MMcf of gas) net to our interest during the twelve months ended December 31, 2008.

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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) | | |
| Proved developed oil reserves (Bbls) | 1,443,782 | 112,173 | |
| Proved undeveloped oil reserves (Bbls) | 114,119 | 16,396 | |
| Total proved oil reserves (Bbls) | 1,557,901 | 128,569 | |
| Proved developed gas reserves (Mcf) | 9,484,586 | 7,929,988 | 4,927,429 |
| Proved undeveloped gas reserves (Mcf) | 7,396,191 | 5,377,520 | 2,165,629 |
| Total proved gas reserves (Mcf) | 16,880,777 | 13,307,508 | 7,093,058 |
| Total proved gas equivalents (Mcf) (1) | 26,228,183 | 14,078,922 | 7,093,058 |
| Present value of estimated future net cash flows before income taxes, discounted at 10% (2) | \$ 28,233 | \$ 27,992 | \$ 8,705 |
| Reconciliation of non-GAAP financial measure: | | | |
| PV-10 (3) | \$ 28,233 | \$ 27,992 | \$ 8,705 |
| Less: Undiscounted income taxes | | | |
| Plus: 10% discount factor | | | |
| Discounted income taxes | | | |
| Standardized 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 utilized 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

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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.

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.

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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 | | |