PostRock Energy Corp
Form 10-K
March 03, 2011

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

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

**For the fiscal year ended December 31, 2010**

**Commission file number: 001-34635**

**PostRock Energy Corporation**
*(Exact Name of Registrant as Specified in Its Charter)*

| | |
|---|---|
| **Delaware**<br>*(State or Other Jurisdiction of Incorporation or Organization)* | **27-0981065**<br>*(I.R.S. Employer Identification No.)* |
| **210 Park Avenue**<br>**Oklahoma City, Oklahoma**<br>*(Address of Principal Executive Offices)* | **73102**<br>*(Zip Code)* |

**Registrant s telephone number, including area code:**
**(405) 600-7704**
**Securities Registered Pursuant to Section 12(b) of the Exchange Act:**

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common Stock, par value $0.01 per share | The NASDAQ Stock Market LLC |

**Securities Registered Pursuant to Section 12(g) of the Exchange Act:**
**None**

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 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 period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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 of 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 o | Non-accelerated filer o<br>(Do not check if a smaller reporting company) | Smaller reporting company þ |

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 common stock held by non-affiliates of the registrant at June 30, 2010, was approximately $32 million, based upon the closing price of $4.72 per share as reported by the NASDAQ on such date.

The aggregate market value of outstanding common stock, including those held by affiliates of the registrant, at March 1, 2011, was approximately $52 million, based upon the closing price of $6.24 per share. There were 8,290,482 shares of common stock outstanding on that date.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the proxy statement for the 2010 Annual Meeting of Stockholders are incorporated by reference in Part III.

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## GLOSSARY

In this report the following abbreviations are used:

| | |
|---|---|
| *Bbl* | Barrel |
| *MBbls* | Thousand barrels |
| *Mcf* | Thousand cubic feet |
| *MMcf* | Million cubic feet |
| *Bcf* | Billion cubic feet |
| *MMcf/d* | Million cubic feet per day |
| *Mcfe* | Thousand cubic feet equivalent. To determine Mcfe, oil is converted on the basis of one barrel of oil equaling six Mcf of gas equivalent. This ratio reflects energy content only. Given recent commodity prices, the price for an Mcf of natural gas is less than 1/20th the price for a barrel of oil. |
| *MMcfe* | Million cubic feet equivalent |
| *Btu* | British thermal unit |
| *MMBtu* | Million British thermal units |

This report contains forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See Item 1A. Risk Factors Disclosure Regarding Forward-Looking Statements.

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# PART I

## ITEM 1. *BUSINESS*

### Background

PostRock Energy Corporation ( PostRock or the Company ) is a Delaware corporation formed in 2009 to combine our predecessor entities, Quest Resource Corporation ( QRCP ), Quest Energy Partners, L.P. ( QELP ) and Quest Midstream Partners, L.P. ( QMLP ) into a single company. In March 2010, we completed the combination of these entities (the Recombination ). Unless the context requires otherwise, references to the Company, we, us and our refer to Postl from the date of the Recombination and to the three predecessor entities on a consolidated basis prior thereto.

### Business Segments

We are an independent oil company engaged in the acquisition, exploration, development, production and gathering of crude oil and natural gas. We manage our business in two segments, production and pipeline.

Our production segment is focused in the Cherokee Basin, a 15-county region in southeastern Kansas and northeastern Oklahoma. We also have minor oil producing properties in Oklahoma and certain other minor gas producing properties in the Appalachian Basin.

Our pipeline segment consists of a 1,120 mile interstate natural gas pipeline (the KPC Pipeline ), which transports natural gas from northern Oklahoma and western Kansas to Wichita and Kansas City. We acquired the KPC Pipeline in November 2007.

### *Production*

Our production in the Cherokee Basin is derived from Pennsylvanian Age coal and shale formations. We believe 90% of our current production comes from the coal formations, which are located at depths between 300 and 1400 feet. In order to understand how to improve our wells performance, we are conducting a series of geologic and engineering studies. These studies include a detailed review of fracture stimulation techniques, electric log data and depositional patterns to identify variables that support higher production rates. We are also evaluating the possibility of finding conventional gas reserves in other geologic horizons.

At December 31, 2010, our Cherokee Basin assets consisted of approximately 2,659 gross and 2,643 net wells capable of production. These wells are on approximately 336,287 net acres of leasehold classified as developed. In the Basin, we have approximately 132,590 net acres currently classified as undeveloped. During 2010, these wells produced at an average daily rate of 50.1 Mmcfe. At year end, our reservoir engineers attributed 121.5 Bcfe of estimated net proved reserves to these properties.

We also have a gathering system in the Cherokee Basin. The system provides a market outlet for gas produced in an approximately 1,000 square mile area. The system has connections to 1 intrastate and 3 interstate pipelines. We gather substantially all of our production in the Basin. In addition, we gather a minor amount of gas produced by others. At year end, daily throughput on the system averaged 64.6 Mmcf of which approximately 6.0% was produced by third parties. Third party gathering contracts generally permit us to retain between 20% and 30% of the gas gathered. We believe ownership of the system is a material competitive advantage in the future development and consolidation of assets in the Basin. The gathering system includes 77 compressors totaling approximately 53,000 horsepower and six

$CO_2$ amine treating facilities. The majority of this compression is rented. The system has an estimated throughput capacity of approximately 85 Mmcf per day. We believe we are the largest producer of gas and have the largest gathering system in the Cherokee Basin.

At December 31, 2010, our Oklahoma assets consist of approximately 39 gross and 22.5 net wells capable of production. These wells are on approximately 1,481 net acres of leasehold classified as developed and additionally, we have approximately 25 net acres classified as undeveloped. During 2010, these wells produced net to our interest at an average daily rate of 170 Bbls. At year end, our reservoir engineers

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attributed 603,840 Bbls of crude oil and 74.2 Mmcf of natural gas, or a total of 3.7 Bcfe, of estimated net proved reserves to these properties.

Giving effect to the sale discussed below, our Appalachian Basin assets consist of approximately 400 gross and 373 net wells capable of production. These wells are on approximately 9,291 net acres of leasehold classified as developed. In this area, we also have approximately 26,815 net acres currently classified as undeveloped. During 2010, these wells produced at an average daily rate of 2.8 Mmcfe, of which approximately 33% was from the properties sold. At year end, also giving effect to the sale discussed below, our reservoir engineers attributed 9.0 Bcfe of estimated net proved reserves to these properties.

We also have a 163 miles gathering system in the Appalachian Basin. The system is connected to two interstate pipelines. At December 31, 2010, this system had a maximum daily throughput of approximately 3 Mmcf. All of our gas production in the area is transported by this system.

*Appalachian Basin Asset Sale* On December 24, 2010, we entered into an agreement with Magnum Hunter Resources Corporation ( MHR ) to sell to MHR certain oil and gas properties and related assets located in Wetzel and Lewis Counties, West Virginia. The sale enabled us to reduce debt and focus on the Cherokee Basin. The sale closed in two phases for $39.7 million. The first phase covered assets located in the Wetzel County which closed on December 30, 2010 for $28 million. The second phase covered assets located in Lewis County which closed on January 14, 2011 for $11.7 million. The amount received at both closings was paid half in cash and half in MHR common stock. The agreement contained provisions for a third closing if certain conditions are met before May 15, 2011. There can be no assurance that the third closing will occur.

***Interstate Pipeline***

Our pipeline is one of four pipelines capable of delivering gas to Kansas City. It has a daily throughput capacity of approximately 160 Mmcf. The pipeline includes three compressor stations with a total of 14,680 horsepower. The majority of this compression is owned. Our pipeline has interconnections with pipelines owned and/or operated by Enogex Inc. ( Enogex ), Panhandle Eastern Pipe Line Company ( PEPL ) and ANR Pipeline Company. These connections enable us to transport gas sourced from the Anadarko and Arkoma Basins, as well as the western Kansas and Oklahoma panhandle producing regions.

The KPC Pipeline is significantly underutilized. To address this problem, we have hired a new KPC Pipeline management team and shut down our Houston office in the course of the last 18 months. Currently, all pipeline management personnel are located in the Oklahoma City corporate office. We are working to increase throughput by creating additional service options for gas suppliers and consumers and developing additional pipeline interconnects to provide customers greater optionality for gas supply and market. In 2010, we added a bidirectional interconnect with PEPL and a delivery capability with Enogex. These interconnects provide our shippers new opportunities. Throughput in 2010 increased 37% from prior year levels and we added 12 new shippers. We have not been able to increase the amount of our capacity that is subject to long-term firm transportation contracts. Our goal is to increase the amount of gas being transported on our pipeline, thereby creating capacity constraints that we believe will lead to long-term firm transportation agreements. To achieve this, we continue to evaluate multiple possibilities, such as transporting gas for producers in close proximity to our pipeline, each intended to create value for the customer while providing incremental profit for the KPC Pipeline.

The KPC Pipeline is regulated by the Federal Energy Regulatory Commission ( FERC ).

Financial information by segment and revenues from external customers are located in Part II, Item 8 Financial Statements and Supplemental Data to this Annual Report on Form 10-K.

**Description of Production Properties and Projects**

***Properties***

We produce Coal Bed Methane ( CBM ) gas out of our properties located in the Cherokee Basin. Geologically, it is situated between the Forest City Basin to the north, the Arkoma Basin to the south, the Ozark Dome to the east and the Nemaha Ridge to the west. The Cherokee Basin is a mature producing area with respect to conventional reservoirs such as the Bartlesville sandstones and the Mississippian limestones, which were developed beginning in the early 1900s.

The Cherokee Basin is part of the Western Interior Coal Region of the central United States. The principal formations we target include the Mulky, Weir-Pittsburgh and the Riverton. These coal seams are blanket type deposits, which extend across large areas of the basin. Each of these seams generally range from two to five feet thick. Additional minor coal seams such as the Summit, Bevier, Fleming and Rowe are found at varying locations throughout the basin. These seams range in thickness from one to two feet.

CBM is unique in that the coal seam serves as both the source rock and the reservoir rock. The storage mechanism is also different. Gas is stored in the pore or void space of the rock in conventional gas, but in CBM, most, and frequently all, of the gas is stored by adsorption. This adsorption leads to gas being stored at relatively low pressures. Another unique characteristic of CBM is that the gas flow can be increased by reducing the reservoir pressure. Frequently, the coal bed pore space, which is in the form of cleats or fractures, is filled with water. The reservoir pressure is reduced by pumping out the water, releasing the methane from the molecular structure, which allows the methane to flow through the cleat structure to the well bore. Because of the necessity to remove water and reduce the pressure within the coal seam, CBM, unlike conventional hydrocarbons, often will not show immediately on initial production testing. Coal bed formations typically require extensive dewatering and de-pressuring before desorption can occur and the methane begins to flow at commercial rates. We use submersible pumps on all new wells and recompletions for more efficient dewatering, which has reduced the amount of time it takes for our CBM wells to achieve peak production rates from up to 12 months to as few as 4 months.

CBM and conventional gas both have methane as their major component. While conventional gas often has more complex hydrocarbon gases, CBM rarely has more than 2% of the more complex hydrocarbons. The CBM produced from our Cherokee Basin properties has a BTU content of approximately 990 BTU per cubic foot, compared to conventional natural gas hydrocarbon production which can typically vary from 1,050- 1,300 BTU per cubic foot. The content of gas within a coal seam is measured through gas desorption testing. The ability to flow gas and water to the wellbore in a CBM well is determined by the fracture or cleat network in the coal. While, at shallow depths of less than 500 feet, these fractures are sometimes open enough to produce the fluids naturally, at greater depths the networks are progressively squeezed shut, reducing the ability to flow naturally. It is necessary to provide other avenues of flow such as hydraulically fracturing the coal seam. By pumping fluids at high pressure, fractures are opened in the coal. A slurry of water, certain chemicals and sand is pumped at high pressures into the fractures, with the sand essentially propping the fractures open. After the release of pressure, the flow of both water and gas is improved, allowing the economic production of gas.

The Appalachian Basin is one of the largest and oldest producing basins in the United States. Our main area of operation in the Appalachian Basin is in West Virginia, where there are producing formations at depths of 1,500 feet to approximately 8,000 feet. Specifically, our main production formations are the lower Devonian Marcellus Shale, the shallow Mississippian (Big Injun, Maxton, Berea, Pocono, Big Lime) and the Upper Devonian (Riley, Benson, Java, Alexander, Elk, Cashaqua, Middlesex, West River and Genesee, including the Huron Shale member, and Rhinestreet Shales).

***Projects***

We are developing our Cherokee Basin properties on a combination of 160-acre and 80-acre spacing. Our wells generally reach total depth in 1.5 days. During 2010, we completed 163 wells, of which 124 wells were drilled prior to 2010. Our cost to drill and complete a well, including the related pipeline infrastructure, was approximately $156,000 during 2010. Although the majority of our project work in the first half of the year was delivered on schedule and under budget, a number of wells did not achieve peak production rate as expected. To better understand the geology and fracture treatments required in the different areas of the Cherokee Basin, we have compiled detailed engineering data and we are continuing to collect data and to perform studies of this data. Based on preliminary findings, we are evaluating the possibility of finding more conventional gas reserves in other geologic zones. Individual well results from the wells drilled in the third and fourth quarter have been mixed, but on the whole these wells are meeting cumulative production targets as budgeted. We continue to further refine our understanding of the geoscience in the Cherokee Basin to improve individual well results.

For 2011, we have budgeted approximately $43.6 million to drill and complete 290 new wells, complete 8 wells drilled in 2010, and recomplete 40 wells. We estimate that for 2011, our average cost for drilling and completing a well, including the related pipeline infrastructure, will be approximately $140,000. The majority of these new wells will be completed on locations that are classified as containing proved reserves in the December 31, 2010 reserve report. We have budgeted $7.3 million for land and equipment capital expenditures. We intend to fund our 2011 capital expenditures with cash flow from operations. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, gas prices, costs and drilling results. See Item 1A. *Risk Factors Risks Related to Our Business Our identified drilling location inventories will be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our results of operations.*

We perforate and fracture stimulate the multiple coal seams and formations present in each well. Our typical Cherokee Basin well has net reserves of approximately 110-140 Mmcf depending on the geological setting and averages an initial daily production rate of 5-10 Mcf while water is pumped off and the formation pressure is lowered. Following what has historically been an initial 4 to 12 month dewatering period, there is a 12 to 18 month period of relatively flat daily production at approximately 40 Mcf, net of shrink. Thereafter, production begins to decline. The standard economic life is approximately 15 years. Through the use of submersible pumps, we have been able to shorten the initial dewatering period closer to 4 months in substantially all new wells.

Our development activities in the Cherokee Basin also include a program to recomplete or convert CBM wells that were originally completed from a single coal seam to wells that produce from multiple coal seams. The recompletion strategy is to add four to five additional pay zones to each wellbore, in a two-stage process at an average cost of approximately $36,000 per well. Adding new zones to an existing well has a brief negative effect on production by first taking the well offline to perform the work and then by introducing a second dewatering phase of the newly completed formations. In the long term, we believe the impact of the multi-seam recompletions and the introduction of submersible pumps to the recompleted wells will result in an increased rate of return. This is due to an increased rate of production, reduced operating costs and an increase in the ultimate recoverable reserves available per well. During 2010, 31 recompletions were undertaken, 29 of which were successfully finished. At December 31, 2010, we believe we have approximately 132 additional wellbores that are candidates for recompletion to multi-seam producers.

During 2010, we drilled three vertical wells in Wetzel County, West Virginia, and had a working interest in two horizontal wells drilled in Lewis County, West Virginia. We experienced significant drilling cost overruns on the wells in which we participated. All five wells were sold to MHR as described above. Our total capital expenditure in the Appalachian Basin in 2010 was $4.3 million. Our 2011 budget does not include any capital expenditure in the Appalachian Basin.

## Oil and Gas Data

### *Preparation of Reserve Reports*

Management has established, and is responsible for, internal controls designed to provide reasonable assurance that our reserve estimation is compared and reported in accordance with rules and regulations promulgated by the

Securities Exchange Commission ( SEC ) as well as established industry practices used by independent engineering firms and our peers. These internal controls include, but are not limited to: 1) documented process workflow timeline, 2) verification of economic data inputs to information supplied by our internal operations accounting, regional production and operations, land, and marketing groups, and 3) senior management review of internal reserve estimations prior to publication.

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Cawley, Gillespie & Associates, Inc. ( CGA ), third-party reserve engineers, prepared our reserves estimates as of December 31, 2010, 2009 and 2008. CGA is an independent firm of petroleum engineers, geologists, geophysicists and petro physicists; they do not own any interest in our properties and are not employed on a contingent fee basis. The technical person responsible for our reserve estimates at CGA meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

***Estimated Reserves***

The following table presents our estimated net proved reserves at December 31, 2010, based on our reserve report. Proved reserves are those quantities of oil and gas, which, by analysis of geo-scientific and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations and prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The data was prepared by CGA. Reserves at December 31, 2010 were determined using the unweighted arithmetic average of the first day of the month price for each month from January through December 2010. These prices were $79.43 per barrel of oil and $4.37 per Mmbtu of gas.

| | Gas (Bcf) | Oil (MMbbl) | Total (Bcfe) | % |
|---|---|---|---|---|
| Proved reserves | | | | |
| Developed | 117.0 | 0.73 | 121.4 | 90% |
| Undeveloped | 13.5 | 0.01 | 13.5 | 10% |
| Total proved reserves | 130.5 | 0.74 | 134.9 | 100% |

Reserve estimates are imprecise and may change as additional information becomes available. Furthermore, estimates of natural gas and oil reserves are projections based on geo-scientific and engineering data. There are uncertainties inherent in the interpretation of this data as well as the projection of future rates of production and the timing of development expenditures. Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. See Item 1A. *Risk Factors Risks Related to Our Business Our estimated reserves are based on many assumptions that may prove to be inaccurate.* Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

At December 31, 2010, we had 13.5 Bcfe of proved undeveloped reserves. During 2010, due to liquidity constraints, we developed only 0.2 Bcfe of our proved undeveloped reserves reported in 2009 while 6.6 Bcfe was sold in 2010 in connection with the Appalachian Basin asset sale to MHR discussed above. At December 31, 2010, we did not have material proved undeveloped reserves that remain undeveloped five years subsequent to their disclosure as proved undeveloped reserves. All of our proved undeveloped reserves included in our 2010 reserve report are scheduled to be developed before 2014.

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***Production Volumes, Sales Prices and Production Costs***

The following table sets forth information regarding our production properties. The production figures reflect the net production attributable to our revenue interest and are not indicative of the total volumes produced by the wells. All sales data excludes the effects of our derivative financial instruments, unless otherwise indicated. During the fourth quarter of 2010, we reclassified the operations and assets of our gathering system in the Cherokee Basin from our former natural gas pipelines segment to our production segment. The costs associated with our gathering system are now considered a component of our production costs. Our results presented below have been revised to reflect the reclassification.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Net Production | | | |
| Gas (Bcf) | 19.2 | 21.2 | 21.3 |
| Oil (Bbls) | 76,583 | 83,015 | 69,812 |
| Gas equivalent (Bcfe) | 19.7 | 21.7 | 21.7 |
| Oil and Natural Gas Sales ($ in thousands) | | | |
| Gas sales | $ 82,153 | $ 75,106 | $ 156,051 |
| Oil sales | 5,783 | 4,787 | 6,448 |
| Total oil and natural gas sales | $ 87,936 | $ 79,893 | $ 162,499 |
| Avg Sales Price (unhedged) | | | |
| Gas ($ per Mcf) | $ 4.27 | $ 3.54 | $ 7.32 |
| Oil ($ per Bbl) | $ 75.51 | $ 57.66 | $ 92.36 |
| Gas equivalent ($ per Mcfe) | $ 4.47 | $ 3.68 | $ 7.47 |
| Avg Sales Price (hedged)(1) | | | |
| Gas ($ per Mcf) | $ 5.92 | $ 8.11 | $ 7.02 |
| Oil ($ per Bbl) | $ 78.63 | $ 69.93 | $ 90.44 |
| Gas equivalent ($ per Mcfe) | $ 6.09 | $ 8.19 | $ 7.18 |
| Operating expenses ($ per Mcfe) | | | |
| Production costs (including gathering costs but excluding production and property taxes) | $ 1.99 | $ 2.11 | $ 2.49 |
| Production and property taxes | $ 0.39 | $ 0.47 | $ 0.55 |
| Net Revenue ($ per Mcfe) | $ 2.08 | $ 1.10 | $ 4.43 |

(1) Data includes the effects of our commodity derivative contracts that do not qualify for hedge accounting.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Realized gain (loss) on hedges | | | |
| Gas Hedges | $ 31,693 | $ 97,130 | $ (6,254) |
| Oil Hedges | 239 | 1,018 | (134) |
| Total | $ 31,932 | $ 98,148 | $ (6,388) |

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The following tables present our production, average sales prices and production costs, excluding production and property taxes, by area for the years ended December 31, 2010 and 2009.

| | Year Ended December 31, 2010 | | Year Ended December 31, 2009 | |
|---|---|---|---|---|
| | **MidContinent(1)** | **Appalachia** | **MidContinent(1)** | **Appalachia** |
| Production | | | | |
| Natural Gas (Bcfe) | 18.3 | 0.9 | 20.3 | 0.9 |
| Oil (Bbls) | 64,326 | 12,257 | 64,583 | 18,432 |
| Total production (Bcfe) | 18.7 | 1.0 | 20.7 | 1.0 |
| Average Sales Prices | | | | |
| Natural Gas (per Mcfe) | $ 4.21 | $ 5.57 | $ 3.31 | $ 8.30 |
| Oil (per bbl) | 76.27 | 71.53 | 59.30 | 51.90 |
| Total average sales price (per Mcfe) | 4.38 | 6.03 | 3.44 | 8.34 |
| Production Costs (per Mcfe) | $ 1.98 | $ 2.30 | $ 2.05 | $ 3.25 |

(1) MidContinent includes the Cherokee Basin and our minor oil producing properties in Oklahoma.

***Producing Wells and Acreage***

The following tables set forth information regarding our ownership of wells and total acres at December 31, 2010, 2009 and 2008. Our data for 2010 includes all wells mechanically capable of production. Our data for 2009 and 2008 includes only producing wells as we could not determine, without unreasonable effort or expense, the number of our nonproducing wells that were mechanically capable of production.

| | Gas | | Oil | | Total | |
|---|---|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| December 31, 2008 | 2,873 | 2,825.0 | 82 | 80.2 | 2,955 | 2,905.2 |
| December 31, 2009 | 2,442 | 2,397.8 | 48 | 43.7 | 2,490 | 2,441.5 |
| December 31, 2010(1) | 3,052 | 2,995.2 | 47 | 44.2 | 3,099 | 3,039.4 |

(1) Increase from 2009 is primarily due to 163 wells completed in 2010 and the inclusion of non-producing wells that are mechanically capable of production that we omitted in prior years.

| | Acreage | | | | | |
|---|---|---|---|---|---|---|
| | **Producing(1)** | | **Nonproducing** | | **Total** | |
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| December 31, 2008(2)(3) | 464,702 | 446,537 | 208,224 | 180,707 | 672,926 | 627,244 |
| December 31, 2009(2)(4) | 446,129 | 432,008 | 139,018 | 130,161 | 585,147 | 562,169 |
| December 31, 2010(5)(6) | 436,566 | 424,778 | 90,498 | 86,392 | 527,064 | 511,170 |

(1) Includes acreage held by production or the payment of shut in royalties under the terms of the lease.

(2) Includes acreage in the states of Kansas, Oklahoma, New York, Pennsylvania, and West Virginia.

(3) Includes approximately 37,723 gross and 31,565 net acres attributable to various farm-out agreements or other mechanisms in the Appalachian Basin. Approximately 6,912 net acres were earned and approximately 24,653 net acres were unearned under these agreements as of December 31, 2008. There are certain drilling or payment obligations that must be met before this unearned acreage is earned.

(4) Includes approximately 37,805 gross and 31,883 net acres attributable to various farm-out agreements or other mechanisms in the Appalachian Basin. Approximately 10,058 net acres are earned and approximately 21,825 net acres are unearned under these agreements as of December 31, 2009. There are certain drilling or payment obligations that must be met before this unearned acreage is earned.

(5) Includes approximately 29,512 gross and 28,928 net acres attributable to various farm-out agreements or other mechanisms in the Appalachian Basin. Approximately 10,700 net acres are earned and approximately 22,799 net acres are unearned under these agreements at December 31, 2010. There are certain drilling or payment obligations that must be met before this unearned acreage is earned.

(6) Includes acreage in the states of Kansas, Oklahoma, West Virginia, and New York.

At December 31, 2010, we had 336,287 net developed and 132,590 net undeveloped acres in the Cherokee Basin and 9,426 net developed acres and 31,385 net undeveloped acres in the Appalachian Basin. Developed acres are acres spaced or assigned to productive wells/units based upon governmental authority or standard industry practice. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas, regardless of whether such acreage contains proved reserves.

***Drilling Activities***

Our drilling, recompletion, abandonment and acquisition activities for the periods indicated are shown below. This information includes wells in all areas in the period in which they were completed.

| | **Year Ended December 31, 2010** | | **Year Ended December 31, 2009** | | **Year Ended December 31, 2008** | |
|---|---|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Exploratory wells drilled | | | | | | |
| Productive | | | | | 1 | 1 |
| Dry | | | 1 | 1 | 1 | 1 |
| Development wells drilled | | | | | | |
| Productive | 163 | 163 | 4 | 2.5 | 339 | 338 |
| Dry | | | | | | |
| Wells plugged and abandoned | (2) | (2) | (11) | (11) | (17) | (17) |
| Wells divested | (7) | (7) | | | | |
| Wells acquired(1) | | | 9 | 1.6 | 551 | 514.5 |
| Net increase in capable wells | 154 | 154 | 3 | (5.9) | 875 | 837.5 |
| Recompletion of old wells | | | | | | |
| Capable of production | 29 | 29 | | | 14 | 14 |

(1) For 2008, includes 54.5 net and 56 gross oil wells capable of production acquired in Seminole County, Oklahoma. The remainder of the wells acquired in 2008 were part of the PetroEdge acquisition.

In addition to the activity above we drilled but did not complete eight vertical wells in the Cherokee Basin and three vertical wells in Wetzel County, West Virginia. The Wetzel County wells were sold before year end. We also had a working interest in two horizontal wells drilled in Lewis County, West Virginia. These wells were awaiting pipeline connection at the end of 2010 and were sold in January 2011.

***Gas Gathering***

| | Year Ended December 31, | |
|---|---|---|
| | 2010 | 2009 |
| Throughput (Mmcf) | | |
| Cherokee Basin | 23,584 | 26,083 |
| Appalachian Basin | 933 | 956 |

***Third-Party Gathering***

We receive fees from third parties to gather their gas on our system. Excluding our royalty owners, approximately 6% of the gas transported on our gathering systems during 2010 was for third parties.

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## Exploration and Production

### *General*

As the operator of wells in which we have an interest, we design and manage the development of these wells and supervise operation and maintenance activities on a day-to-day basis. We employ production and reservoir engineers, geologists and other specialists.

Field operations conducted by our personnel include duties performed by pumpers or employees whose primary responsibility is to operate the wells. Other field personnel are experienced and involved in the activities of well servicing, the development and completion of new wells and the construction of supporting infrastructure for new wells (such as electric service, disposal wells and gas well flow lines). The primary equipment we own is trucks, well service rigs, stimulation assets and construction equipment. At times we utilize third-party contractors to supplement our field personnel.

In the Cherokee Basin, we provide, on an in-house basis, many of the services required for the completion and maintenance of our CBM wells. Internally sourcing these functions significantly reduces our reliance on third-party contractors, which typically provide these services. We believe that we are able to realize significant cost savings because we can reduce delays in executing our plan of development and avoid paying price markups. We currently rely on third-party contractors to drill our wells. Once a well is drilled, either we or a third-party contractor run the casing. We perform the cementing, fracturing and stimulation in completing our own wells. We have our own fleet of 23 well service units that we use in the process of completing our wells, and to perform remedial field operations required to maintain production from our existing wells. In the Appalachian Basin, we rely on third-party contractors for these services.

### *Leases*

As of December 31, 2010, we had approximately 4,033 leases covering approximately 511,170 net acres. The typical oil and gas lease provides for the payment of royalties to the mineral owner for all oil or gas produced from any well drilled on the lease premises. This amount ranges from 12.5% to 18.75% resulting in an 81.25% to 87.5% net revenue interest to us.

Because the acquisition of oil and natural gas leases is a very competitive process, and involves certain geological and business risks to identify productive areas, prospective leases are sometimes held by other operators. In order to gain the right to drill these leases, we may purchase leases from them.

In the Cherokee Basin, at year end, we held leases on approximately 468,878 net acres, of which 79,017 net acres are not currently held by production. Unless we establish commercial production on the properties subject to these leases during their term, these leases will expire. Leases covering approximately 16,117 net acres are scheduled to expire before December 31, 2011. If these leases expire and are not renewed, we will lose the right to develop the related properties.

In the Appalachian Basin, we hold oil and natural gas leases and development rights by virtue of farm-out agreements or similar mechanisms on 22,799 net acres that are still within their original lease or agreement term and are not earned or are not held by production. Unless we establish commercial production on the properties or fulfill the requirements specified by the various leases or agreements, during the prescribed time periods, these leases or agreements will expire.

## Marketing and Major Customers

***Production***

During 2010, approximately 70% of our Cherokee Basin and Oklahoma gas production was sold to ONEOK Energy Marketing and Trading Company (ONEOK) and approximately 82% and 18% of our oil production was sold to Sunoco Partners Marketing & Terminals L.P. and Coffeyville Refining, respectively. The ONEOK sales agreement is a monthly evergreen agreement, cancellable by either party. Prior to 2010, substantially all our gas production in the Cherokee Basin was sold to ONEOK; however, in late 2009 we diversified our gas sales in the Cherokee Basin between eight markets, including sales directly to end users. We will seek to continue to diversify our sales portfolio balancing price, credit risk, and volume risk which is expected to reduce marketing risk and provide competition to optimize the price we receive for our production.

Approximately 90% of our 2010 Appalachian Basin gas production was sold to Dominion Field Services under a mix of fixed price and index based sales contracts and a market sensitive contract and 100% of our oil production in the Appalachian Basin was sold to Appalachian Oil Purchasers, a division of Clearfield Energy. The remainder was sold to various purchasers under market sensitive pricing arrangements.

If we were to lose any of these purchasers, we believe that we would be able to promptly replace them because we believe there are multiple options for marketing our commodities. We have discussed direct sales with refineries and industrials as well as establishing agreements with various marketing companies. The physical location of our production provides ample options for marketing the commodities to creditworthy parties.

***Interstate Pipeline***

The primary shipper on the KPC Pipeline in 2010 was Kansas Gas Service ( KGS ). KGS is a division of ONEOK and is the local distribution company in Kansas for Kansas City and Wichita as well as a number of other municipalities. For 2010, approximately 76% of the revenue from the KPC Pipeline was from transportation contracts with KGS. The remaining 24% was from a mix of short-term firm transportation, interruptible transportation and park and loan contracts.

KGS s contracts for firm capacity on the KPC Pipeline step down in volumes in the future. The following table presents the average volumes for the periods indicated:

| Capacity | Time Period |
|---|---|
| 57,568 Dth/d | Through October 31, 2012 |
| 44,636 Dth/d | November 1, 2012 through October 31, 2015 |
| 43,171 Dth/d | November 1, 2015 through October 31, 2017 |
| 12,000 Dth/d | November 1, 2009 through October 31, 2013 |
| 6,900 Dth/d | November 1, 2002 through September 30, 2017 |
| 6,857 Dth/d | November 1, 2002 through March 31, 2017 |

**Commodity Derivative Activities**

Commodity prices were volatile in 2010 and prices for crude oil and natural gas are affected by a variety of factors beyond our control. When commodity futures prices have been at appropriate levels we have used derivative instruments to reduce commodity price uncertainty and increase cash flow predictability inherent to the marketing of our production. At this time, we believe commodity prices are not at levels that warrant actively hedging. When prices improve, we intend to resume our hedging activity. For additional information about our derivatives, see Part I, Item 1A *Risk Factors* *Our hedging activities could result in financial losses or reduce our income* and Part II, Item 7A Quantitative and Qualitative Disclosures About Market Risk.

**Competition**

***Production***

We operate in a highly competitive environment for acquiring properties, marketing our production and employing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. As a result, our competitors may be able to pay more for properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in our industry.

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### *Interstate Pipeline*

We compete with other interstate and intrastate pipelines in the transportation of natural gas for transportation customers primarily on the basis of transportation rates, access to competitively priced supplies of natural gas, markets served by the pipelines, and the quality and reliability of transportation services. In Kansas City, our major competitors include Southern Star Central Gas Pipeline, Kinder Morgan Interstate Gas Transmission s Pony Express Pipeline and Panhandle Eastern Pipe Line Company. In Wichita, our major competitors include Southern Star Central Gas Pipeline, Atmos Energy Corporation and Mid-Continent Market Center.

## Title

### *Production Properties*

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved developed reserves. Prior to the commencement of development operations on those properties, we conduct a title examination and perform curative work with respect to significant defects that we discover. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence development operations on a property until we have cured any material title defects that we discover on such property. We believe that we have satisfactory title to our material producing properties in accordance with standards generally accepted in our industry.

Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. In some cases lands over which leases have been obtained are subject to prior liens which have not been subordinated to the leases. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects.

### *Pipeline Rights-of-Way*

Substantially all of our gathering systems and the KPC Pipeline are constructed within rights-of-way granted by property owners named in the appropriate land records. All of our compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

Our property or rights-of-way are subject to encumbrances, restrictions and other imperfections. These imperfections have not interfered, and we do not expect that they will materially interfere, with the conduct of our business. In many instances, lands over which rights-of-way have been obtained are subject to prior liens which have not been subordinated to the right-of-way grants. In some cases, not all of the owners named in the appropriate land records have joined in the right-of-way grants, but in substantially all such cases signatures of the owners of majority interests have been obtained. Substantially all permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets, and state highways, where necessary. Substantially all permits have also been obtained from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor s election.

Certain of our rights to lay and maintain pipelines are derived from recorded oil and natural gas leases for wells that are currently in production; however, the leases are subject to termination if the wells cease to produce. In most cases, the right to maintain existing pipelines continues in perpetuity, even if the well associated with the lease ceases to be productive. In addition, because some of these leases affect wells at the end of lines, these rights-of-way will not be used for any other purpose once the related wells cease to produce.

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## Seasonality

### *Production*

Freezing weather and storms in the winter and flooding in the spring and summer have in the past resulted in a number of our wells being off-line for a short period of time. This adversely affects our production volumes and revenues and increases our lease operating costs due to the time spent by field employees to bring the wells back on-line. In the past this has also resulted in wells producing at lower rates for extended periods after returning to production. We have recently had success managing this exposure by using heat tape on wells and compressors to limit the amount of production that goes offline and heavy equipment to facilitate faster access to wells to return them to production after outages.

### *Interstate Pipeline*

Due to the nature of the markets served by the KPC Pipeline, primarily the Wichita and Kansas City markets heating load, the utilization rate of the KPC Pipeline has traditionally been much higher in the winter months (November through March) than in the remainder of the year. As a result, KPC s firm capacity transportation agreements have greater utilization in the winter months. KPC currently generates a disproportionate share of its revenue in the winter months.

## Government Regulation

Exploration for, and production and marketing of, crude oil and natural gas are extensively regulated at the federal, state and local levels by a number of federal, state and local governmental authorities under various laws and regulations governing a wide variety of matters, including allowable rates of production, plugging of abandoned wells, transportation, prevention of waste and pollution, protection of the environment and worker health and safety. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of injunctive relief or both.

These laws are under constant review for amendment or expansion. Moreover, the possibility exists that new legislation or regulations may be adopted. Amended, expanded or new laws and regulations increasing the regulatory burden on the crude oil and natural gas industry can have a significant impact on our operations or our customers ability to use natural gas and may require us or our customers to change their operations significantly or incur substantial costs. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the US Environmental Protection Agency ( EPA ), the Federal Energy Regulatory Commission ( FERC ), the Bureau of Ocean Energy Management, Regulation and Enforcement, the Commodity Futures Trading Commission ( CFTC ), state commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations. See Part I, Item 1A. Risk Factors *We are subject to increasing governmental regulations and environmental risks that may cause us to incur substantial cost* and *Pipeline integrity programs and repairs may impose significant costs and liabilities on us.*

Management believes that our operations comply in all material respects with applicable laws and regulations and that the existence and enforcement of such laws and regulations have no more restrictive effect on our method of operations than on other similar companies in the energy industry. We have internal procedures and policies that we believe help to ensure that our operations are conducted in substantial regulatory compliance. Governmental regulations applicable to our operations include those relating to environmental matters, exploration and production activities, interstate pipeline and FERC regulations, natural gas gathering pipelines, natural gas sales, and pipeline safety.

*Environmental Matters*

Our operations are subject to various increasingly stringent federal, state and local laws and regulations relating to the discharge of materials into, and the protection of, the environment and imposing liability for

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pollution. We have made and will continue to make expenditures in our efforts to comply with these requirements. We do not believe that we have, to date, expended material amounts in connection with such activities or that compliance with these requirements will have a material adverse effect on our capital expenditures, earnings or competitive position. Although such requirements do have a substantial impact on the oil and gas industry, to date, we do not believe they have affected us to any greater or lesser extent than other companies in the industry. Due to the size of our operations, significant new environmental regulation could have a disproportionate adverse effect on our operations. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders limiting or enjoining future operations or imposing additional compliance requirements or operational limitation on such operations. See Part I, Item 1A Risk Factors *We are subject to increasing governmental regulations and environmental risks that may cause us to incur substantial costs* ; *We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental and operational safety regulations or an accidental release of hazardous substances into the environment* ; *We may face unanticipated water and other waste disposal costs* ; and *Recent and future environmental laws and regulations may significantly limit, and increase the cost of, our exploration, production and transportation operations.*

***Production***

Federal, state and local regulations apply to our exploration and production activities and impose permitting, bonding and reporting requirements. Most states, and some counties and municipalities, in which we operate also regulate the location and method of drilling and casing of wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells; and/or notice to surface owners and other third parties. Some state laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while others rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and reduce our interest in the unitized properties. In addition, some state conservation laws establish maximum rates of production from oil and gas wells. These laws generally prohibit venting or flaring of gas and impose requirements regarding the ratability of production. Moreover, some states impose a production or severance tax on the production and sale of oil, gas and gas liquids within its jurisdiction.

The Cherokee Basin has been an active producing region for a number of years. Many of our properties had abandoned oil and conventional gas wells on them at the time the current lease was entered. A number of these wells remain unplugged or were improperly plugged by a prior landowner or operator. Many of the former operators of these wells have ceased operations and cannot be located or do not have the financial resources to plug these wells. We believe that we are not responsible for plugging an abandoned well on one of our leases, unless we have used, attempted to use or invaded the abandoned well bore in our operations on the land or have otherwise agreed to assume responsibility for plugging the wells. While the Kansas Corporation Commission s ( KCC ) current interpretation of Kansas law is consistent with our position, it could change in the future.

***Interstate Pipelines and FERC Regulation***

Certain of our operations are subject to regulation by FERC. FERC regulates the terms, conditions and rates for interstate transportation and storage services, as well as various other matters relating to pipeline and storage services, operations, and construction. Our KPC Pipeline is an interstate natural gas pipeline system that is subject to FERC s regulatory requirements. See Part I, Item 1A Risk Factors *The KPC Pipeline is subject to regulation by FERC, which could have an adverse impact on our ability to establish transportation rates that would allow us to recover the full cost of operating the KPC pipeline, plus a reasonable return, which may affect our business and results of operations.*

FERC regulates interstate natural gas pipelines pursuant to the NGA, NGPA and The Energy Policy Act of 2005 ( EP Act 2005 ). FERC regulation affects the price and terms for access to natural gas pipeline

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transportation. FERC is continually proposing and implementing new rules and regulations applicable to providers of interstate transportation and storage services. Under certain circumstances, these initiatives also may affect the intrastate transportation of natural gas. In October 2010, FERC issued a Notice of Inquiry seeking comment on whether and how holders of firm capacity on intrastate natural gas pipelines providing interstate transportation and storage services should be permitted to allow others to make use of their firm interstate capacity. We cannot predict the ultimate impact of these regulatory changes to our operations. We do not believe that we will be affected by any such FERC action materially differently than other industry participants with which we compete.

Maintaining compliance with FERC requirements on a continuing basis requires us to incur various expenses. Additional compliance expenses could be incurred if new or amended laws or regulations are enacted or existing laws or regulations are reinterpreted. In recent years, FERC has initiated various audits of pipeline compliance activities and commenced investigations of the rates charged by certain pipelines. Failure to comply with FERC regulations could subject us to penalties and fines. See Part I, Item 1A Risk Factors *We could be subject to penalties and fines if we fail to comply with FERC regulations.*

Our natural gas gathering pipeline facilities are generally exempt from FERC s jurisdiction and regulation pursuant to Section 1(b) of the NGA, which exempts pipeline facilities that perform primarily a gathering function, rather than a transportation function. However, if FERC were to determine that the facilities perform primarily a transmission function, rather than a gathering function, these facilities may become subject to regulation as interstate natural gas pipeline facilities and we may be subject to fines and additional costs and regulatory burdens that would substantially increase our operating costs and would adversely affect our profitability. See Part I, Item 1A Risk Factors *A change in the jurisdictional characterization of some of our gathering assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our gathering assets, which may indirectly cause our revenues to decline and operating expenses to increase*

***State Regulation of Gathering Pipelines***

Our gathering pipeline operations are currently limited to the States of Kansas, Oklahoma, New York, and West Virginia. State regulation of gathering facilities generally includes various permitting, safety, environmental and, in some circumstances, nondiscriminatory take requirements, and complaint-based rate regulation. We are licensed as an operator of a natural gas gathering system with the KCC and are required to file periodic information reports with it. We are not required to be licensed as an operator or to file reports in Oklahoma, New York or West Virginia.

On those portions of our gathering system that are open to third-party producers, the producers have the ability to file complaints challenging our gathering rates, terms of services and practices. We have contracts with all of the third-party producers for which we gather gas and are not aware of any complaints being filed. Our fees, terms and practices must be just, reasonable, not unjustly discriminatory and not unduly preferential. If the KCC or the Oklahoma Corporation Commission ( OCC ), as applicable, were to determine that the rates charged to a complainant did not meet this standard, the KCC or the OCC, as applicable, would have the ability to adjust our rates with respect to the wells subject to the complaint. We are not aware of any instance in which either the KCC or the OCC has made such a determination in the past.

These regulatory burdens may affect profitability, and management is unable to predict the future cost or impact of complying with such regulations. While state regulation of pipeline transportation does not materially affect our operations, we do own several small, discrete delivery laterals in Kansas that are subject to a limited jurisdiction certificate issued by the KCC. As with FERC regulation described above, state regulation of pipeline transportation may influence certain aspects of our business and the market price for our products.

***Sales of Natural Gas***

The price at which we buy and sell natural gas currently is not subject to federal regulation or, for the most part, state regulation. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC s jurisdiction. These initiatives may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations.

***Interstate Pipeline Safety***

Our pipelines are subject to regulation by the U.S. Department of Transportation (the DOT ) under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. We believe that our pipeline operations are in substantial compliance with applicable NGPSA requirements; however, if new or amended laws and regulations are enacted or existing laws and regulations are reinterpreted, future compliance with the NGPSA could result in increased costs.

## Employees

As of December 31, 2010, we had 231 field employees in offices located in Kansas, Oklahoma, Pennsylvania, and West Virginia. We have 69 executive and administrative personnel located at our headquarters in Oklahoma City. None of our employees are covered by a collective bargaining agreement and management considers its relations with employees to be satisfactory.

## Where To Find Additional Information

Additional information about us can be found on our website at www.pstr.com. Information on our website is not part of this document. We also provide free of charge on our website our filings with the SEC, including our annual reports, quarterly reports and current reports, along with any amendments thereto, as soon as reasonably practicable after we have electronically filed such material with, or furnished it to, the SEC.

You may also find information related to our corporate governance, board committees and company code of ethics at our website. Among the information you can find there is the following:

- Audit Committee Charter;
- Compensation Committee Charter;
- Nominating and Corporate Governance Committee Charter; and
- Code of Business Conduct and Ethics.

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## ITEM 1A. *RISK FACTORS*

### Risks Related to Our Business

***Energy prices are very volatile, and if commodity prices remain low or decline, our revenues, profitability and cash flows will be adversely affected. A sustained or further decline in oil and gas prices may adversely affect our business, financial condition or results of operations and our ability to fund our capital expenditures and meet our financial commitments.***

The prices we receive for our oil and gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil and gas are commodities; therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile and will likely continue to be volatile in the future. For example, during 2010, the near month NYMEX natural gas futures price ranged from a high of $6.01 per Mmbtu to a low of $3.29 per Mmbtu. As of March 1, 2011, the near month NYMEX natural gas futures price was 3.87 per Mmbtu. Approximately 98% of our production is natural gas. The prices that we receive for our production, and the levels of our production, depend on a variety of factors that are beyond our control, such as:

- domestic and foreign supply of and demand for oil and gas;
- price and level of foreign imports of oil and gas;
- level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and gas producing countries, including embargoes and continued hostilities in the Middle East and other sustained military campaigns, acts of terrorism or sabotage;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- the impact of the U.S. dollar exchange rates on oil and gas prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the costs, proximity and capacity of gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and gas, and a drop in prices will significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

reduce the amount of cash flow available for capital expenditures, including for the drilling of wells and the construction of infrastructure to transport the gas it produces;

negatively impact the value of our reserves because declines in oil and gas prices would reduce the amount of oil and gas we can produce economically;

reduce the drilling and production activity of our third-party customers and increase the rate at which our customers shut in wells;

potentially reduce gas available for transport on the KPC Pipeline; and

limit our ability to borrow money or raise additional capital.

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***We may be required to write-down the carrying value of our assets.***

Lower oil and gas prices may not only decrease our revenues, profitability and cash flows, but also reduce the amount of oil and gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated reserves. Substantial decreases in oil and gas prices have had and may continue to render a significant number of our planned exploration and development projects uneconomic. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil or gas properties, pipelines or other long-lived assets for impairments. We will be required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and may therefore, require a write-down of such carrying value. For example, we recognized a ceiling test impairment of $102.9 million related to our oil and gas properties during the first quarter of 2009. We also recorded impairment charges of $53.6 million on our interstate pipeline and related contract-based intangible assets as well as $112.2 million on our gathering system assets in the fourth quarter of 2009. The impairment charge on our interstate pipeline and contract-based intangible assets was due to the loss of a significant customer during the fourth quarter of 2009. Our gathering system impairment resulted from a reduction in projected future gathering revenues anticipated with our Cherokee Basin production. The reduction in future gathering revenues was partially the result of limits imposed by our former credit facilities on our capital expenditures and consequently on our ability to further develop acreage in the Cherokee Basin, the geographic region served by our gathering system. This reduced the future projected revenues of the gathering system at that time. We may incur further impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred and result in a reduction in our credit facility borrowing base.

***We have reduced debt but we remain highly leveraged.***

At December 31, 2010, we had $254.8 million of contractual commitments outstanding, consisting of debt service requirements and non-cancelable operating lease commitments. Of such amount, $187.0 million was outstanding under our $350 million secured borrowing base revolving credit facility with a current borrowing base of $225 million, which borrowing base may not be increased without the consent of all lenders under the facility. The borrowing base may be reduced in connection with future borrowing base redeterminations, the first of which will be effective on July 31, 2011. There has been a significant decline in oil and gas prices since the borrowing base was last determined. As a result, we currently expect the borrowing base to be reduced in connection with the redetermination as of July 31, 2011. Any reduction in the borrowing base will reduce our available liquidity, and, if the reduction results in the outstanding amount under the facility exceeding the borrowing base, we will be required to repay the deficiency within 30 days or in six monthly installments thereafter, at our election.

Our ability to borrow funds will depend upon a number of factors, including the condition of the financial markets. Under certain circumstances, the use of leverage may create a greater risk of loss to stockholders than if we did not borrow. The risk of loss in such circumstances is increased because we would be obligated to meet fixed payment obligations on specified dates regardless of our cash flow. If we do not make our debt service payments when due, our lenders may foreclose on assets securing such debt.

Our future level of debt could have important consequences, including the following:

- our ability to obtain additional debt or equity financing, if necessary, for drilling, expansion, working capital and other business needs may be impaired or such financing may not be available on favorable terms;

a substantial decrease in our revenues as a result of lower oil and gas prices, decreased production or other factors could make it difficult for us to pay our liabilities. Any failure by us to meet these obligations could result in litigation, non-performance by contract counterparties or bankruptcy;

our funds available for operations and future business opportunities will be reduced by that portion of our cash flow required to make principal or interest payments on our debt;

we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our indebtedness, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness or seeking additional equity capital. We may not be able to affect any of these remedies on satisfactory terms or at all.

***Our credit agreements have substantial restrictions and financial covenants that restrict our business and financing activities.***

The operating and financial restrictions and covenants in our credit agreements restrict our ability to finance future operations or capital needs and to engage, expand or pursue our business activities. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by our results of operations and financial conditions and events or circumstances beyond our control. If market or other economic conditions do not improve, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit agreements, our indebtedness may become immediately due and payable, the interest rates on our credit agreements may increase and the lenders commitment, if any, to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments in which event we may be forced to file for bankruptcy.

For a description of our credit facilities, please read Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Agreements and Note 10 in Part II, Item 8.

***An increase in market interest rates will cause our debt service obligations to increase.***

Borrowings under our credit agreements bear interest at floating rates. The rates are subject to adjustment based on fluctuations in market interest rates. An increase in the interest rates associated with our floating-rate debt would increase our debt service costs and affect our results of operations and cash flow. In addition, an increase in our interest expense could adversely affect our future ability to obtain financing or materially increase the cost of any additional financing.

***We may be unable to pass through all of our costs and expenses for gathering and compression to royalty owners under our gas leases, which would reduce our net income and cash flows.***

We incur costs and expenses for gathering, dehydration, treating and compression of the gas that we produce. The terms of some of our existing gas leases and other development rights may not, and the terms of some of the gas leases and other development rights that we may acquire in the future may not, allow us to charge the full amount of these costs and expenses to the royalty owners under the leases or other agreements. On August 6, 2007, certain mineral interest owners filed a putative class action lawsuit against our wholly owned subsidiary Quest Cherokee, that, among other things, alleges Quest Cherokee improperly charged certain expenses to the mineral and/or overriding royalty interest owners under leases covering the acres leased by Quest Cherokee in Kansas. We will be responsible for any judgments or settlements with respect to this litigation. Please see Part I, Item 3 Legal Proceedings for a discussion of this litigation. To the extent that we are unable to charge and recover the full amount of these costs and expenses from our royalty owners, our net income and cash flows will be reduced.

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***We are exposed to trade credit risk in the ordinary course of our business activities.***

We are exposed to risks of loss in the event of nonperformance by our customers and by counterparties to our derivative contracts. Some of our customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our customers and/or counterparties could adversely affect our results of operations and financial condition.

***Unless we replace the reserves that we produce, our existing reserves and production will decline, which would adversely affect our revenues, profitability and cash flows.***

Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and gas reserves, production and cash flow depend on our success in developing and exploiting our reserves efficiently and finding or acquiring additional recoverable reserves economically. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs or production from our existing wells could decline at a faster rate than we have estimated, which would adversely affect our business, financial condition and results of operations. Factors that may hinder our ability to acquire additional reserves include competition, access to capital, prevailing gas prices and attractiveness of properties for sale.

***Our estimated reserves are based on assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.***

It is not possible to measure underground accumulations of oil and gas in an exact way. Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of oil and gas that cannot be directly measured and assumptions concerning future oil and gas prices, production levels and operating and development costs. In estimating our level of oil and gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- a constant level of future oil and gas prices;
- geological conditions;
- production levels;
- capital expenditures;
- operating and development costs;
- the effects of governmental regulations and taxation; and
- availability of funds.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly. Additionally, there recently has been increased debate and disagreement over the classification of reserves, with particular focus on proved undeveloped reserves. Changing interpretations of the classification standards or disagreements with our interpretations could cause us to write-down reserves. Please read Future price declines may result in a write-down of our asset carrying values.

Our standardized measure is calculated using unhedged oil and gas prices and is determined in accordance with the rules and regulations of the SEC. The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the market value of our estimated proved reserves. The estimated discounted future net cash flows from our estimated proved reserves is based on twelve month

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average prices and current costs in effect on the day of estimate. However, actual future net cash flows from our oil and gas properties also will be affected by factors such as:

- the actual prices we receive for oil and gas;
- our actual operating costs in producing oil and gas;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- supply of and demand for oil and gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with the FASB Accounting Standards Codification Topic 932, *Extractive Activities Oil and Gas*, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

***Drilling for and producing oil and gas is a costly and high-risk activity with many uncertainties that could adversely affect our financial condition or results of operations.***

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. The cost of drilling, completing and operating a well is often uncertain, and cost factors, as well as the market price of oil and gas, can adversely affect the economics of a well. Furthermore, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of drilling rigs, equipment, labor or other services;
- adverse weather conditions;
- difficulty disposing of water produced as part of the coal bed methane production process;
- equipment failures or accidents;
- title problems;
- pipe or cement failures or casing collapses;
- compliance with environmental and other governmental requirements;
- environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- lost or damaged oilfield drilling and service tools;
- loss of drilling fluid circulation;

- unexpected operational events and drilling conditions;
- increased risk of wellbore instability due to horizontal drilling;
- unusual or unexpected geological formations;
- natural disasters, such as fires and floods;
- blowouts, surface craterings and explosions; and
- uncontrollable flows of oil, gas or well fluids.

A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances. We may drill

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wells that are unproductive or, although productive, do not produce oil or gas in economic quantities. Unsuccessful drilling activities could result in higher costs without any corresponding revenues. Furthermore, a successful completion of a well does not ensure a profitable return on the investment.

***The revenues of our interstate pipeline business are generated under contracts that must be renegotiated periodically.***

In the past, substantially all of the revenues from the KPC Pipeline were generated under two firm capacity transportation contracts with Kansas Gas Service and one firm capacity transportation contract with Missouri Gas Energy. The contracts with KGS generated 59% and 58% of total revenues from the KPC Pipeline for the years ended December 31, 2009 and 2008, respectively, and the contract with MGE generated 32% and 38% of total revenues from the KPC Pipeline for the years ended December 31, 2009 and 2008, respectively. The MGE firm contract, which was for 46,000 Dth/d, expired on October 31, 2009, and was not renegotiated or renewed. The loss of this contract resulted in a non-cash impairment charge related to the KPC Pipeline recorded in 2009. The remaining KGS contracts generated 76% of total KPC Pipeline revenue in 2010 and volume steps down in future years.

If we are unable to extend or replace our firm capacity transportation contracts when they expire or renegotiate them on terms as favorable as the existing contracts, we could suffer a material reduction in revenues, earnings and cash flows. In particular, our ability to extend and replace contracts could be adversely affected by factors we cannot control, including:

- competition by other pipelines, including the change in rates or upstream supply of existing pipeline competitors, as well as the proposed construction by other companies of additional pipeline capacity in markets served by our interstate pipeline;

- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire;

- reduced demand and market conditions in the areas we serve;

- the availability of alternative energy sources or natural gas supply points; and

- regulatory actions.

***Our hedging activities could result in financial losses or reduce our income.***

We have and may in the future enter into additional derivative arrangements for a significant portion of our production that could result in both realized and unrealized losses on our derivative financial instruments. The extent of our commodity price exposure is related largely to the scope of our hedging activities.

The prices at which we enter into derivative financial instruments covering our production in the future will be dependent upon commodity prices at the time we enter into these transactions, which may be substantially lower than current prices or the prices under our existing derivative financial instruments. Accordingly, our commodity price risk management strategy will not protect us from significant and sustained declines in oil and gas prices received for our future production. Conversely, our commodity price risk management strategy may limit our ability to realize cash flow from commodity price increases. Furthermore, we have a policy that requires, and our credit facilities mandate, that those derivative transactions relate to only a portion of our expected production volumes. As a result, we have direct commodity price exposure on the portion of our production volumes that is not covered by a derivative financial instrument.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our hedging activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

***Because of our lack of asset and geographic diversification, adverse developments in our operating areas would adversely affect our results of operations.***

Substantially all of our assets are located in the Cherokee Basin. As a result, our business is disproportionately exposed to adverse developments affecting this region. Potential adverse developments could result from, among other things, changes in governmental regulation, capacity constraints with respect to the pipelines connected to our wells, curtailment of production, natural disasters or adverse weather conditions in or affecting these regions. Due to our lack of diversification in asset type and location, an adverse development in our business or this operating area would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets and operating areas.

***The oil and gas industry is highly competitive and we may be unable to compete effectively with larger companies, which may adversely affect our results of operations.***

The oil and gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel, and we compete with other companies that have greater resources. Many of our competitors are major and large independent oil and natural gas companies, and they not only drill for and produce oil and gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. Our larger competitors also possess and employ financial, technical and personnel resources substantially greater than our resources. These companies may be able to pay more for oil and gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and gas industry. These larger companies may have a greater ability to continue drilling activities during periods of low oil and gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material impact on our business activities, results of operations and financial condition.

With respect to the KPC Pipeline, we compete with other interstate and intrastate pipelines in the transportation of gas for transportation customers primarily on the basis of transportation rates, access to competitively priced supplies of gas, markets served by the pipeline, and the quality and reliability of transportation services. Major competitors include Southern Star Central Gas Pipeline, Inc., Kinder Morgan Interstate Gas Transmission s Pony Express Pipeline and Panhandle Eastern Pipe Line Company in the Kansas City market and Southern Star Central Gas Pipeline, Inc., Atmos Energy Corporation and Mid-Continent Market Center in the Wichita market.

Natural gas also competes with other forms of energy available to our customers, including electricity, coal, hydroelectric power, nuclear power and fuel oil. The impact of competition could be significantly increased as a result of factors that have the effect of significantly decreasing demand for natural gas in the markets served by our pipelines, such as competing or alternative forms of energy, adverse economic conditions, weather, higher fuel costs, and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas.

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***Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.***

There are a variety of risks inherent in our operations that may generate liabilities, including contingent liabilities, and financial losses to us, such as:

- damage to wells, pipelines, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, farm and utility equipment;
- leaks of gas or oil spills as a result of the malfunction of equipment or facilities;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses.

We are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. We do not have property insurance on any of our underground pipeline systems or wellheads that would cover damage to the pipelines. Pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Premiums and deductibles for certain insurance policies have increased substantially in recent years. Due to these cost increases, we may not be able to obtain the levels or types of insurance we would otherwise have obtained, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition and results of operations.

***Certain of our undeveloped acreage is subject to leases or other agreements that may expire in the near future.***

In the Cherokee Basin, as of December 31, 2010, we held leases on approximately 468,878 net acres, of which 79,087 net acres are not currently held by production. Unless we establish commercial production on the properties subject to these leases during their term, these leases will expire. Leases covering approximately 16,117 net acres are scheduled to expire before December 31, 2011. If these leases expire and are not renewed, we will lose the right to develop the related properties.

***Our identified drilling location inventories will be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our results of operations.***

Our management has specifically identified drilling locations for our future multi-year drilling activities on our existing acreage. We have identified, based on reserves at December 31, 2010, approximately 128 gross proved undeveloped drilling locations in the Cherokee Basin. These identified drilling locations represent a significant part of our future long-term development drilling program. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, gas prices, costs and drilling results. The assignment of proved reserves to these locations is based on the assumptions regarding gas prices in our December 31, 2010, reserve report. Our final determination of whether to drill any of these drilling locations will be dependent upon the factors described above, our financial condition, our ability to obtain additional capital as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, it is possible that not all of the numerous drilling locations identified will be drilled within the timeframe specified in the reserve report or will ever be drilled, and we do not know if we will be able to produce gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could have a significant adverse effect on our financial condition and results of operations.

***We may incur losses as a result of title deficiencies in the properties in which we invest.***

If an examination of the title history of a property reveals that an oil or gas lease or other developed rights has been purchased in error from a person who is not the owner of the mineral interest desired, our interest would substantially decline in value. In such an instance, the amount paid for such lease or leases or other developed rights would be lost. It is management s practice, in acquiring leases, or undivided interests in leases or other developed rights, not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, we will rely upon the judgment of lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease or other developed rights in a specific mineral interest.

Prior to drilling a well, however, it is the normal practice in the industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such curative work entails expense. The work might include obtaining affidavits of heirship or causing an estate to be administered. Our failure to obtain these rights may adversely impact our ability in the future to increase production and reserves.

***A change in the jurisdictional characterization of some of our gathering assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our gathering assets, which may indirectly cause our revenues to decline and operating expenses to increase.***

Section 1(b) of the NGA exempts gas gathering facilities from FERC jurisdiction. We believe that the facilities comprising our gathering systems meet the traditional tests used by FERC to distinguish nonjurisdictional gathering facilities from jurisdictional transportation facilities, and that, as a result, our gathering systems are not subject to FERC s jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of regular litigation. The classification and regulation of some of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress. If FERC were to determine that the facilities perform primarily a transmission function, rather than a gathering function, these facilities may become subject to regulation as interstate natural gas pipeline facilities and we may be subject to fines. We believe the expenses associated with seeking certificate authority for construction, service and abandonment, establishing rates and a tariff for these other facilities, and meeting the detailed regulatory accounting and reporting requirements, if these actions were to become necessary, would substantially increase our operating costs and would adversely affect our profitability.

FERC regulation will still affect our gathering systems and the markets for our natural gas. FERC s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, could indirectly affect our gathering systems. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, FERC may not continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity.

Although natural gas gathering facilities are exempt from FERC jurisdiction under the NGA, such facilities are subject to rate regulation when owned by an interstate pipeline and other forms of regulation by

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the state in which such facilities are located. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, open access requirements and rate regulation. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that a number of interstate pipeline companies have transferred gathering facilities to unregulated affiliates. Our gathering operations are limited to the States of Kansas, Oklahoma and West Virginia. We are licensed as an operator of a natural gas gathering system with the KCC and are required to file periodic information reports with the KCC. We are not required to be licensed as an operator or to file reports in Oklahoma or West Virginia.

Our gathering operations may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. In the future, the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Additionally, while gathering facilities and other non-interstate pipelines are generally exempt from FERC s jurisdiction, FERC has adopted internet posting requirements that are applicable to certain gathering facilities and other non-interstate pipelines that deliver more than 50 million MMBtu on an annual basis. Our gathering facilities do not currently meet this size threshold and are, therefore, not currently subject to the posting requirements. Nevertheless, it is possible that we could become subject to the posting requirements in the future if, for example, the size threshold were to be lowered or the throughput on our gathering facilities were to increase. If we were to become subject to the posting requirements, we would likely incur additional compliance expenses.

***The KPC Pipeline is subject to regulation by FERC, which could have an adverse impact on our ability to establish transportation rates that would allow us to recover the full cost of operating the KPC pipeline, plus a reasonable return, which may affect our business and results of operations.***

Rates charged by interstate natural gas pipelines may generally not exceed the just and reasonable rates approved by FERC, unless they are filed as negotiated rates and accepted by the FERC. In addition, interstate natural gas pipelines are prohibited from granting any undue preference to any person, or maintaining any unreasonable difference in their rates, terms, or conditions of service. Consistent with these requirements, the rates, terms, and conditions of the natural gas transportation services provided by interstate pipelines are governed by tariffs approved by FERC.

We own and operate the KPC Pipeline, an interstate natural gas pipeline system that is subject to these regulatory requirements. The KPC Pipeline is a 1,120-mile interstate natural gas pipeline system, which transports natural gas from Oklahoma and western Kansas to the metropolitan markets of Wichita and Kansas City. As an interstate natural gas pipeline, the KPC Pipeline is subject to FERC s jurisdiction and the regulatory requirements summarized above. Maintaining compliance with these requirements on a continuing basis requires us to incur various expenses. Additional compliance expenses could be incurred if new or amended laws or regulations are enacted or existing laws or regulations are reinterpreted.

Additionally, in recent years, FERC has initiated various audits of pipeline compliance activities and commenced investigations of the rates charged by certain pipelines. We may incur additional regulatory expenses if FERC were to commence such an audit or investigation with respect to the KPC Pipeline. The recourse rates set forth in the KPC Pipeline s tariff could also be affected by such an investigation. Likewise, the KPC Pipeline s customers, the state commissions that regulate certain of those customers, and other interested parties also have the right to file complaints seeking changes in the KPC Pipeline tariff, including with respect to the transportation rates stated therein.

As an interstate natural gas pipeline, the KPC Pipeline is subject to regulation by FERC under the NGA. FERC s regulation of interstate natural gas pipelines extends to such matters as:

rates and charges for natural gas transportation services;

certification and construction of new facilities;

extension or abandonment of services and facilities;

maintenance of accounts and records;

relationships between pipelines and certain affiliates;

terms and conditions of service;

depreciation and amortization policies;

acquisition and disposition of facilities; and

initiation and discontinuation of services.

The KPC Pipeline may only charge transportation rates that it has been authorized to charge by FERC. In addition, FERC prohibits natural gas companies from engaging in any undue preference or discrimination with respect to rates or terms and conditions of service. The maximum recourse rates that it may charge for transportation services are established through FERC s ratemaking process, and those recourse rates, as well as the terms and conditions of service, are set forth in the KPC Pipeline s FERC-approved tariff. Pipelines may also negotiate rates that are higher than the maximum recourse rates stated in their tariffs, provided such rates are filed with, and approved by, FERC. Under the NGA, existing rates may be challenged by complaint or by FERC on its own initiative, and any proposed rate increases may be challenged by protest and are subject to approval by FERC. Any successful challenge against the KPC Pipeline s current rates or any future proposed rates could adversely affect our revenues.

Generally and absent settlement, the maximum filed recourse rates for interstate pipelines are based on the cost of service plus an approved return on investment, the equity component of which may be determined through the use of a proxy group of similarly-situated companies. Other key determinants in the ratemaking process are debt costs, depreciation expense, operating costs of providing service, including an income tax allowance, and volume throughput and contractual capacity commitment assumptions.

The likely future regulations under which we will operate the KPC Pipeline may change; FERC periodically revises and refines its ratemaking and other policies in the context of rulemakings, pipeline-specific adjudications, or other regulatory proceedings. FERC s policies may also be modified when FERC decisions are subjected to judicial review. Changes to ratemaking policies may in turn affect the rates we can charge for transportation service.

***We could be subject to penalties and fines if we fail to comply with FERC regulations***

EP Act 2005 gave FERC increased oversight and penalty authority relating to market manipulation and enforcement. EP Act 2005 amended the Natural Gas Act of 1938, or NGA, to prohibit market manipulation. It also amended the NGA and the Natural Gas Policy Act of 1978, or NGPA, to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of FERC issued pursuant to those statutes to up to $1,000,000 per day, per violation. In addition, FERC has adopted regulations regarding market manipulation, which make it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to FERC s jurisdiction, to defraud, make an untrue statement or omit a material fact, or engage in any practice, act or course of business that operates or would operate as a fraud.

Given the complex and evolving nature of FERC regulation, we may incur significant costs related to compliance with FERC regulations. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EP Act 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,000,000 per day for each violation, and to order disgorgement of profits associated with any violation. FERC s enforcement authority also includes the options of revoking or modifying existing certificate authority and referring matters to the United States Department of Justice for criminal prosecution. Since enactment of the EP Act 2005, FERC has initiated a number of enforcement proceedings and imposed penalties on various regulated entities, including other interstate natural gas pipelines.

***We could be subject to regulations adopted by the Commodity Futures Trading Commission pursuant to the Dodd-Frank Act.***

The CFTC has proposed several regulations, pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act ) enacted into law in July 2010, that related to the trading of derivatives, including natural gas derivatives. Given the complex and evolving nature of CFTC regulation, we may incur significant costs related to compliance with CFTC regulations, and such regulations, to the extent they apply to our activities, may affect our ability to enter into favorable transactions. We do not believe that we will be affected by any such CFTC action materially differently than other industry participants with which we compete.

***We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental and operational safety regulations or an accidental release of hazardous substances into the environment.***

We may incur significant costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and gas exploration, development, production, gathering and transportation activities. These costs and liabilities could arise under a wide range of federal, state and local environmental, health and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example, (1) the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions, (2) federal and state laws and regulations currently under development to address GHG emissions, (3) the federal Resource Conservation and Recovery Act and comparable state laws that regulate the management of waste from our facilities, 4) the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ( CERCLA ) and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties owned or operated by us or our predecessors or locations where we or our predecessors sent waste for disposal and (5) the federal Clean Water Act and the Safe Drinking Water Act and analogous state laws and regulations that impose detailed permit requirements and strict controls regarding water quality and the discharge of pollutants into waters of the United States and state waters. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders limiting or enjoining future operations or imposing additional compliance requirements or operational limitation on such operations. Certain environmental laws, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of oil and natural gas, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance.

***We may face unanticipated water and other waste disposal costs.***

We may be subject to regulation that restricts our ability to discharge water produced as part of our gas production operations. Productive zones frequently contain water that must be removed in order for the gas to

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produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce gas in commercial quantities. The produced water must be transported from the lease and injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability.

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies, or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;
- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

The Resource Conservation and Recovery Act ( RCRA ), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous solid wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. In the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, and waste oils, which may be regulated as hazardous wastes. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements. However, drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, production and transportation of oil and gas are currently excluded from regulation as hazardous wastes under RCRA. These wastes may be regulated by EPA or state agencies as non-hazardous solid wastes. Moreover, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

***Pipeline integrity programs and repairs may impose significant costs and liabilities on us.***

Pursuant to the Pipeline Safety Improvement Act of 2002, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for intrastate and interstate natural gas and natural gas liquids pipelines located near high consequence areas, where a leak or rupture could do the most harm. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;

repair and remediate the pipeline as necessary; and

implement preventive and mitigating actions.

KPC completed all baseline assessments of the covered high consequence area integrity testing in 2009 for approximately $200,000. KPC had no expenditures in 2010 to implement pipeline integrity management program testing. KPC also incurred costs of approximately $400,000 in 2009 and $30,000 in 2010 to complete

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the last year of a Stray Current Survey resulting from a 2005 DOT audit. KPC plans to conduct in-line inspections on a small portion of lines in its high consequence area in order to comply with the preventive and mitigation rule from the US Department of Transportation Pipeline and Hazardous Materials Safety Administration ( PHMSA ). The in-line inspections are budgeted to cost approximately $400,000. Results of this initial inspection will help define requirements for future years. As part of the KPC Integrity Plan, KPC will begin its reassessment program of high consequence areas in 2012 with 26 miles of pipeline to be reassessed in Kansas City area and 32 miles of pipeline to be reassessed in the Wichita area. These costs may be significantly higher than what KPC has estimated or previously incurred due to the following factors:

- our estimate does not include the costs of repairs, remediation or preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which could be substantial;

- additional regulatory requirements that are enacted could significantly increase the amount of these expenditures;

- the actual implementation costs may be materially higher than our estimates because of increased industry-wide demand for contractors and service providers and the related increase in costs; or

- failure to comply with DOT regulations and any corresponding deadlines, which could subject us to penalties and fines.

***Recent and future environmental laws and regulations may significantly limit, and increase the cost of, our exploration, production and transportation operations.***

Recent and future environmental laws and regulations, including additional federal and state restrictions on greenhouse gas emissions ( GHG ) that may be passed in response to climate change concerns, may increase our capital and operating costs and also reduce the demand for the oil and natural gas we produce. The oil and gas industry is a direct source of certain GHG emissions, such as carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. The EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule, which requires many suppliers of fossil fuels or industrial chemicals, manufacturers of vehicles and engines, and other facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year to begin collecting GHG emissions data under a new reporting system as of January 1, 2010 with the first annual report due March 31, 2011. In November 2010, the EPA issued final regulations requiring the annual reporting of GHG emissions from qualifying facilities in the upstream oil and natural gas sector, including onshore production (Subpart W). Although the Mandatory Reporting Rule does not control greenhouse gas emission levels from any facilities, it has still caused us to incur monitoring and reporting costs for emissions that are subject to the rule. Further, the rule s new requirements for reporting of fugitive and vented methane emissions from the oil and gas industry can be expected to increase our monitoring and reporting costs during 2011.

After a series of regulatory actions finalized by EPA between December 2009 and May 2010, greenhouse gases became pollutants subject to regulation under the Clean Air Act s Prevention of Significant Deterioration air quality permit program for stationary sources, and the largest of these sources have also become subject to permitting requirements under the Clean Air Act s Title V permitting program. As a result, new major stationary sources of greenhouse gas emissions, and modifications of existing major stationary sources that significantly increase their greenhouse gas emissions will require a permit setting forth Best Available Control Technology for those emissions. EPA has, through its Tailoring Rule, acted to limit these permitting requirements to only the largest sources of greenhouse gas emissions initially, but these new requirements could in the future affect our operations and our ability to obtain air permits for new or modified facilities.

The U.S. Congress has also considered legislation to mandate reductions of greenhouse gas emissions, and at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures intended to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs.

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Federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which we conduct business could adversely affect the demand for our products and could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have a material adverse effect on our business.

In addition, the U.S. Congress is currently considering certain other legislation which, if adopted in its current proposed form, could subject companies involved in oil and natural gas exploration and production activities to substantial additional regulation. If such legislation is adopted, federal tax incentives could be curtailed, and hedging activities as well as certain other business activities of exploration and production companies could be limited, resulting in increased operating costs. Any such limitations or increased capital expenditures and operating costs could have a material adverse effect on our business.

***Our ability to grow and to increase our profitability may depend in part on our ability to make acquisitions. Acquisitions are subject to a number of risks.***

Our ability to grow and to increase our profitability may depend in part on our ability to make acquisitions that result in an increase in our net income per share and cash flows. We may be unable to make such acquisitions because we are: (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors. If we are unable to acquire properties containing proved reserves, our total level of proved reserves will decline as a result of our production, which will adversely affect our results of operations. Even if we do make acquisitions that we believe will increase our net income per share and cash flows, these acquisitions may perform below our expectations and nevertheless result in a decrease in net income and/or cash flows.

***If third-party pipelines and other facilities interconnected to our gas pipelines become unavailable to transport or produce gas, our revenues and cash flows could be adversely affected.***

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Since we do not own or operate any of these pipelines or other facilities, their continuing operation is not within our control. If any of these third-party pipelines and other facilities become unavailable to transport or produce gas, our revenues and cash flows could be adversely affected.

***Failure of the gas that we gather on our gas gathering systems to meet the specifications of interconnecting interstate pipelines could result in curtailments by the interstate pipelines.***

Gas gathered on our gathering systems is delivered into interstate pipelines. These interstate pipelines establish specifications for the gas that they are willing to accept, which include requirements such as hydrocarbon dewpoint, temperature, and foreign content including water, sulfur, carbon dioxide and hydrogen sulfide. These specifications vary by interstate pipeline. If the gas delivered from our gathering systems fails to meet the specifications of a particular interstate pipeline that pipeline may refuse to accept all or a part of the gas scheduled for delivery to it. In those circumstances, we may be required to find alternative markets for that gas or to shut-in the producers of the non-conforming gas, potentially reducing our throughput volumes and revenues.

***We do not own all of the land on which our pipelines are located or on which we may seek to locate pipelines in the future, which could disrupt our operations and growth.***

We do not own the land on which our pipelines have been constructed, but we do have right-of-way and easement agreements from landowners and governmental agencies, some of which require annual payments to maintain the agreements and most of which have a perpetual term. New pipeline infrastructure construction may subject us to more onerous terms or to increased costs if the design of a pipeline requires redirecting. Such costs could have a material adverse effect on our business, results of operations and financial condition.

In addition, the construction of additions to the pipelines may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to expand pipelines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way. If the cost of obtaining new rights-of-way increases, then our business and results of operations could be adversely affected.

***Our success depends on our key management personnel, the loss of any of whom could disrupt our business.***

The success of our operations and activities is dependent to a significant extent on the efforts and abilities of our management. We have not obtained, and we do not anticipate obtaining, key man insurance for any of our management. The loss of services of any of our key management personnel could have a material adverse effect on our business. If the key personnel do not devote significant time and effort to the management and operation of the business, our financial results may suffer.

### Risks Related to the Ownership of Our Common Stock

***The price of our common stock has been and may continue to experience volatility.***

The price of our common stock has been and may continue to be volatile. In addition to the risk factors described above, some of the factors that could affect the price of our common stock are quarterly increases or decreases in revenue or earnings, changes in revenue or earnings estimates by the investment community, sales of our common stock by significant stockholders, short-selling of our common stock by investors, issuance of a significant number of shares for equity-based compensation or to raise additional capital to fund our operations, changes in market valuations of similar companies and speculation in the press or investment community about our financial condition or results of operations, as well as any doubt about our ability to continue as a going concern. General market conditions and U.S. or international economic factors and political events unrelated to the performance of us may also affect our stock price. For these reasons, investors should not rely on recent trends in the price of our common stock to predict the future price of our common stock or our financial results.

***Our charter and bylaws contain provisions that may make it more difficult for a third party to acquire control of us, even if a change in control would result in the purchase of our stockholders common stock at a premium to the market price or would otherwise be beneficial to our stockholders.***

There are provisions in our restated certificate of incorporation and bylaws that may make it more difficult for a third party to acquire control of us, even if a change in control would result in the purchase of our stockholders common stock at a premium to the market price or would otherwise be beneficial to our stockholders. For example, our restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, provisions of our restated certificate of incorporation and bylaws, including limitations on stockholder actions by written consent and on stockholder proposals and director nominations at meetings of stockholders, could make it more difficult for a third party to acquire control of us. Delaware corporation law may also discourage takeover attempts that have not been approved by our board of directors.

***We do not expect to pay dividends on our common stock for the foreseeable future.***

We do not expect to pay dividends on our common stock for the foreseeable future. In addition, our credit agreements prohibit us from paying any dividends without the consent of the lenders under the applicable credit agreement, other than dividends payable solely in our equity interests.

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***White Deer Energy L.P. and its affiliates ( White Deer ) beneficially own approximately 70% of our common stock after giving effect to the exercise of their outstanding warrants, giving White Deer influence and control in corporate transactions and other matters, including a sale of our Company.***

At March 1, 2011, after giving effect to the exercise of its outstanding warrants, White Deer beneficially owns 19,584,205 shares, or approximately 70%, of our common stock. In addition, we have agreed to issue White Deer additional warrants on each quarterly dividend payment date of the Series A Preferred Stock prior to July 1, 2013 on which dividends are not paid in cash but instead accrue. Until December 31, 2011, White Deer, as the holder of the Series B Preferred Stock issued with the warrants, is limited to 45% of the votes applicable to all outstanding voting stock, which limit includes any common stock held by White Deer. After December 31, 2011, the limit only restricts the voting of the Series B Preferred Stock, and White Deer may vote any shares of common stock held by it without regard to that limit.

As a result of its ownership, White Deer effectively will be our controlling stockholder and able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other stockholders, the outcome of certain corporate transactions or other matters submitted to our stockholders for approval, including, for example, potential mergers or acquisitions, asset sales and other significant corporate transactions. The interests of White Deer may not coincide with the interests of other holders of our common stock.

Subject to certain restrictions, White Deer may make investments in companies that compete with us. In addition, our interests may conflict with those of White Deer with respect to, among other things, business opportunities that may be presented to White Deer and to our directors associated with White Deer.

***Substantial sales of our common stock by White Deer could cause our stock price to decline.***

We are unable to predict whether significant amounts of our common stock will be sold by White Deer. Any sales of substantial amounts of our common stock in the public market by White Deer, or the perception that these sales might occur, could lower the market price of our common stock.

**Forward-Looking Statements**

Various statements in this report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements include those regarding projections and estimates concerning the timing and success of specific projects; financial position; business strategy; budgets; amount, nature and timing of capital expenditures; drilling of wells and construction of pipeline infrastructure; acquisition and development of oil and gas properties and related pipeline infrastructure; timing and amount of future production of oil and gas; operating costs and other expenses; estimated future net revenues from oil and gas reserves and the present value thereof; cash flow and anticipated liquidity; funding of our capital expenditures; ability to meet our debt service obligations; and other plans and objectives for future operations.

When we use the words believe, intend, expect, may, will, should, anticipate, could, estimate, plan their negatives, or other similar expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The factors impacting these risks and uncertainties include, but are not limited to:

current weak economic conditions;

volatility of oil and gas prices;

benefits or effects of the Recombination;

increases in the cost of drilling, completion and gas gathering or other costs of developing and producing our reserves;

our debt covenants;

access to capital, including debt and equity markets;

results of our hedging activities;

drilling, operational and environmental risks; and

regulatory changes and litigation risks.

You should consider carefully the statements in Part I, Item 1A Risk Factors and other sections of this Annual Report on Form 10-K, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

We have based these forward-looking statements on our current expectations and assumptions about future events. The forward-looking statements in this report speak only as of the date of this report; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. Readers are urged to carefully review and consider the various disclosures made by us in our reports filed with the SEC, which attempt to advise interested parties of the risks and factors that may affect our business, financial condition, results of operation and cash flows. If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, our actual results may vary materially from those expected or projected.

## ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

## ITEM 2. *PROPERTIES*

We have described our properties, reserves, acreage, wells, production and drilling activity in Part I, Item 1. Business of this Annual Report on Form 10-K.

### Administrative Facilities

The office space for the corporate headquarters for us and our subsidiaries is leased and is located at 210 Park Avenue, Oklahoma City, Oklahoma 73102. The office lease is for 10 years expiring August 31, 2017 covering approximately 35,000 square feet.

We own four buildings within the vicinity of Chanute, Kansas that are used for operations offices, a geological laboratory, an operations terminal and a repair facility. We own an additional building and storage yard in Lenapah, Oklahoma.

Through a subsidiary we lease approximately 4,744 square feet of office space located at 2200 Georgetowne Drive, Sewickley, Pennsylvania 15143. Since administrative duties have been transferred to Oklahoma City, our subsidiary has secured a sub-lease tenant for a portion the remaining term of its lease, which expires on August 1, 2013. Our subsidiary leases approximately 1,500 square feet of office space for field personnel in Harrisville, West Virginia under an annual lease expiring on August 31, 2011.

We have 9,801 square feet of leased office space at 3 Allen Center, 333 Clay Street, Houston, Texas 77002. This space is currently not utilized. The office lease expires on May 6, 2015.

We have leased facilities at Olathe, Wichita, and Medicine Lodge, Kansas for the operations of our interstate pipeline. The Olathe office consists of approximately 7,650 square feet for a lease term of five years expiring October 31, 2011. The Wichita office consists of approximately 1,240 square feet on an annual lease expiring December 31, 2011. The Medicine Lodge field office is leased on a month-to-month basis.

## ITEM 3. *LEGAL PROCEEDINGS*

We are subject, from time to time, to certain legal proceedings and claims in the ordinary course of conducting our business. We will record a liability related to our legal proceedings and claims when we have determined that it is probable that we will be obligated to pay and the related amount can be reasonably

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estimated, and we will disclose the related facts in the footnotes to our financial statements, if material. If we determine that an obligation is reasonably possible, we will, if material, disclose the nature of the loss contingency and the estimated range of possible loss, or include a statement that no estimate of loss can be made. We are currently a defendant in the litigation listed below. We intend to vigorously defend the claims asserted in said litigation. We are unable to predict the outcome of these proceedings or reasonably estimate a range of possible loss that may result.
Like other oil and natural gas producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Therefore it is extremely difficult to reasonably quantify future environmental related expenditures.

**Federal Class Action Securities Litigation**

***Michael Friedman, individually and on behalf of all others similarly situated v. Quest Energy Partners LP, Quest Energy GP LLC, Quest Resource Corporation, Jerry Cash, and David E. Grose, Case No. 08-cv-936-M, U.S. District Court for the Western District of Oklahoma, filed September 5, 2008***

***James Jents, individually and on behalf of all others similarly situated v. Quest Resource Corporation, Jerry Cash, David E. Grose, and John Garrison, Case No. 08-cv-968-M, U.S. District Court for the Western District of Oklahoma, filed September 12, 2008***

***J. Braxton Kyzer and Bapui Rao, individually and on behalf of all others similarly situated v. Quest Energy Partners LP, Quest Energy GP LLC, Quest Resource Corporation and David E. Grose, Case No. 08-cv-1066-M, U.S. District Court for the Western District of Oklahoma, filed October 6, 2008***

***Paul Rosen, individually and on behalf of all others similarly situated v. Quest Energy Partners LP, Quest Energy GP LLC, Quest Resource Corporation, Jerry Cash, and David E. Grose, Case No. 08-cv-978-M, U.S. District Court for the Western District of Oklahoma, filed September 17, 2008***

Four class action complaints were filed in the United States District Court for the Western District of Oklahoma naming QRCP, QELP and Quest Energy GP, LLC, the general partner of the predecessor of QELP ( QEGP ), and certain of their then current and former officers and directors as defendants. The complaints were filed by certain stockholders on behalf of themselves and other stockholders who purchased QRCP common stock between May 2, 2005, and August 25, 2008, and QELP common units between November 7, 2007, and August 25, 2008. The complaints assert claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as amended (the Exchange Act ), and Rule 10b-5 promulgated thereunder, and Sections 11 and 15 of the Securities Act of 1933. The complaints allege that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material facts concerning certain unauthorized transfers of funds from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaints also allege that, as a result of these actions, QRCP s stock price and the unit price of QELP were artificially inflated during the class period. On December 29, 2008, the Court consolidated these complaints. On July 9, 2010, a stipulation of settlement was filed in the consolidated federal action. On August 13, 2010, the Court entered an order preliminarily approving the settlement. On November 29, 2010, the Court approved the settlement and issued its Order and Final Judgment dismissing with prejudice all the federal individual and class securities actions as well as the federal derivative actions described herein. The settlement, however, did not become effective until the consolidated state court derivative cases were dismissed. Those derivative cases were dismissed on January 26, 2011, and the settlement became final as of that date. We contributed $1.0 million to the settlement of the lawsuits and agreed to pay approximately $400,000 representing a portion of associated defense costs of certain individual defendants. These amounts have been substantially paid as of December 31, 2010.

**Federal Individual Securities Litigation**

***Bristol Capital Advisors v. Quest Resource Corporation, Inc., Jerry Cash, David E. Grose, and John Garrison, Case No. CIV-09-932, U.S. District Court for the Western District of Oklahoma, filed August 24, 2009***

On August 24, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma naming QRCP and certain then current and former officers and directors as defendants. The complaint was filed by an individual stockholder of QRCP. The complaint asserts claims under Sections 10(b) and 20(a) of the Exchange Act. The complaint alleges that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material information concerning unauthorized transfers from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaint also alleges that QRCP issued false and misleading statements and or/concealed material information concerning a misappropriation by its former chief financial officer, Mr. David E. Grose, of $1 million in company funds and receipt of unauthorized kickbacks of approximately $850,000 from a company vendor. The complaint also alleges that, as a result of these actions, QRCP s stock price was artificially inflated when the plaintiff purchased their shares of QRCP common stock. On November 29, 2010, the action was dismissed with prejudice as part of the settlement referred to above.

***J. Steven Emerson, Emerson Partners, J. Steven Emerson Roth IRA, J. Steven Emerson IRA RO II, and Emerson Family Foundation v. Quest Resource Corporation, Inc., Quest Energy Partners L.P., Jerry Cash, David E. Grose, and John Garrison, Case No. 5:09-cv-1226-M, U.S. District Court for the Western District of Oklahoma, filed November 3, 2009***

On November 3, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma naming QRCP, QELP, and certain then current and former officers and directors as defendants. The complaint was filed by individual shareholders of QRCP stock and individual purchasers of QELP common units. The complaint asserts claims under Sections 10(b) and 20(a) of the Exchange Act. The complaint alleges that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material information concerning unauthorized transfers from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaint also alleges that QRCP and QELP issued false and misleading statements and/or concealed material information concerning a misappropriation by its former chief financial officer, Mr. David E. Grose, of $1 million in company funds and receipt of unauthorized kickbacks of approximately $850,000 from a company vendor. The complaint also alleges that, as a result of these actions, the price of QRCP stock and QELP common units was artificially inflated when the plaintiffs purchased QRCP stock and QELP common units. The plaintiffs seek $10 million in damages. On November 29, 2010, the action was dismissed with prejudice as part of the settlement referred to above.

**Federal Derivative Cases**

***James Stephens, derivatively on behalf of nominal defendant Quest Resource Corporation v. William H. Damon III, Jerry Cash, David Lawler, David E. Grose, James B. Kite Jr., John C. Garrison and Jon H. Rateau, Case No. 08-cv-1025-M, U.S. District Court for the Western District of Oklahoma, filed September 25, 2008***

On September 25, 2008, a complaint was filed in the United States District Court for the Western District of Oklahoma, purportedly on QRCP s behalf, which named certain of QRCP s then current and former officers and directors as defendants. The factual allegations mirror those in the class actions described above, and the complaint asserts claims for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets, and unjust enrichment. The complaint seeks disgorgement, costs, expenses, and equitable and/or injunctive relief. On November 29, 2010, the action was dismissed with prejudice as part of the settlement referred to above.

***William Dean Enders, derivatively on behalf of nominal defendant Quest Energy Partners, L.P. v. Jerry D. Cash, David E. Grose, David C. Lawler, Gary Pittman, Mark Stansberry, J. Philip McCormick, Douglas Brent Mueller, Mid Continent Pipe & Equipment, LLC, Reliable Pipe & Equipment, LLC, RHB Global, LLC, RHB, Inc., Rodger H. Brooks, Murrell, Hall, McIntosh & Co. PLLP, and Eide Bailly LLP, Case No. CIV-09-752-M, U.S. District Court for the Western District of Oklahoma, filed July 17, 2009***

On July 17, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma, purportedly on QELP s behalf, which named certain of its then current and former officers and directors, external auditors and vendors. The factual allegations relate to, among other things, the transfers and lack of effective internal controls. The complaint asserts claims for breach of fiduciary duty, waste of corporate assets, unjust enrichment, conversion, disgorgement under the Sarbanes-Oxley Act of 2002, and aiding and abetting breaches of fiduciary duties against the individual defendants and vendors and professional negligence and breach of contract against the external auditors. The complaint seeks monetary damages, disgorgement, costs and expenses and equitable and/or injunctive relief. It also seeks injunctive relief requiring QELP to take all necessary actions to reform and improve its corporate governance and internal procedures. On November 29, 2010, the action was dismissed with prejudice as part of the settlement referred to above.

**State Court Derivative Cases**

***Tim Bodeker, derivatively on behalf of nominal defendant Quest Resource Corporation v. Jerry Cash, David E. Grose, Bob G. Alexander, David C. Lawler, James B. Kite, John C. Garrison, Jon H. Rateau and William H. Damon III, Case No. CJ-2008-9042, District Court of Oklahoma County, State of Oklahoma, filed October 8, 2008***

***William H. Jacobson, derivatively on behalf of nominal defendant Quest Resource Corporation v. Jerry Cash, David E. Grose, David C. Lawler, James B. Kite, Jon H. Rateau, Bob G. Alexander, William H. Damon III, John C. Garrison, Murrell, Hall, McIntosh & Co., LLP, and Eide Bailly, LLP, Case No. CJ-2008-9657, District Court of Oklahoma County, State of Oklahoma, filed October 27, 2008***

***Amy Wulfert, derivatively on behalf of nominal defendant Quest Resource Corporation, v. Jerry D. Cash, David C. Lawler, Jon C. Garrison, John H. Rateau, James B. Kite Jr., William H. Damon III, David E. Grose, N. Malone Mitchell III, and Bryan Simmons, Case No. CJ-2008-9042 consolidated December 30, 2008, District Court of Oklahoma County, State of Oklahoma (Original Case No. CJ-2008-9624, filed October 24, 2008)***

The factual allegations in these petitions mirror those in the class actions discussed above. All three petitions assert claims for breach of fiduciary duty, abuse of control, gross mismanagement, and unjust enrichment. The *Jacobson* petition also asserts claims against the two auditing firms named in that suit for professional negligence and aiding and abetting the director defendants breaches of fiduciary duties. The *Wulfert* petition also asserts a claim against Mr. Bryan Simmons for aiding and abetting Mr. Cash s and Mr. Grose s breaches of fiduciary duties. The petitions seek damages, costs, expenses, and equitable relief. On March 26, 2009, the court consolidated these actions as *In re Quest Resource Corporation Shareholder Derivative Litigation*, Case No. CJ-2008-9042. In conjunction with the settlement of the securities and derivative cases, on January 26, 2011, an agreed order of dismissal was entered in the consolidated action.

**Royalty Owner Class Action**

***Hugo Spieker, et al. v. Quest Cherokee, LLC, Case No. 07-1225-MLB, U.S. District Court for the District of Kansas, filed August 6, 2007***

The Company was named as a defendant in a putative class action lawsuit filed by several royalty owners in the U.S. District Court for the District of Kansas. The putative class consists of all royalty and overriding royalty owners in the Kansas portion of the Cherokee Basin. Plaintiffs contend that the Company failed to properly make royalty payments by, among other things, paying royalties based on sale volumes rather than wellhead volumes, by allocating expenses in excess of actual costs, by improperly allocating production costs

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and marketing costs to royalty owners, and by failing to pay interest on royalty payments made late. The Company has filed an answer, denying plaintiffs claims.

The parties have participated in multiple mediation sessions with the most recent in January 2011, and continue to engage in settlement discussions. The parties have agreed to a period of limited discovery with another mediation to occur thereafter. If the matter cannot be resolved at that time, the case will proceed with general discovery, a class certification hearing, and a trial on the merits. The Company has recorded an accrual of $1.0 million related to this case.

**Litigation Related to Oil and Gas Leases**

***Billy Bob Willis, et al. v. Quest Resource Corporation, et al., Case No. CJ-09-063, District Court of Nowata County, State of Oklahoma, filed April 28, 2009***

***Larry Reitz, et al. v. Quest Resource Corporation, et al., Case No. CJ-09-076, District Court of Nowata County, State of Oklahoma, filed May 22, 2009***

The above-referenced lawsuits, which were filed in April and May 2009, respectively, have been consolidated to proceed as a single action. Plaintiffs are royalty interest owners located in Nowata and Craig counties. They allege that defendants have wrongfully deducted post-production costs from the plaintiffs royalties and have engaged in self-dealing contracts and agreements resulting in a less than market price for the gas production. Plaintiffs seek unspecified actual and punitive damages. Limited discovery has taken place. Trial will likely occur in October, 2011. The parties have participated in settlement discussions and a mediation which was held February 25, 2011. A second mediation is scheduled for March 9, 2011.

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# 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 listed on the NASDAQ Stock Market LLC under the symbol PSTR. The common stock began trading on March 8, 2010, the trading day following the consummation of the Recombination. The table below presents the high and low price for each quarter since trading of our common stock began.

| Quarter Ended | High | Low |
|---|---|---|
| March 31, 2010(1) | $ 22.98 | $ 8.12 |
| June 30, 2010 | $ 11.02 | $ 4.51 |
| September 30, 2010 | $ 5.89 | $ 2.75 |
| December 31, 2010 | $ 5.20 | $ 3.39 |

(1) Represents the high and low prices for the period from March 8, 2010 through March 31, 2010.

The closing price for our common stock on March 1, 2011 was $6.24 per share. As of March 1, 2011, there were 8,290,482 shares of common stock outstanding held of record by approximately 86 stockholders. Additionally, warrants to purchase 19,584,205 shares of our common stock at a weighted average exercise price of $3.16 per share were outstanding and held by White Deer.

### Dividends

The payment of dividends on our common stock is within the discretion of the board of directors and is dependent upon many factors. We have not declared any dividends on our common stock and do not anticipate paying any dividends on our common stock in the foreseeable future. Our credit facilities contain restrictions on our ability to pay dividends.

### Unregistered Sales of Equity Securities

The information set forth in Note 12 in Part II, Item 8 of this Annual Report is incorporated herein by reference in response to this item. The additional warrants and shares of Series B preferred stock issued to White Deer were issued in reliance upon an exemption from registration pursuant to Section 4(2) under the Securities Act of 1933, as amended, which exempts transactions by an issuer not involving any public offering.

### Issuer Purchases of Equity Securities

None.

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## ITEM 6. *SELECTED FINANCIAL DATA*

We have derived the following selected consolidated financial information for PostRock as of and for the period ended December 31, 2010, and for our predecessor for the period from January 1 March 5, 2010, and as of December 31, 2009 and for the years ended December 31, 2009 and 2008, from the audited consolidated financial statements of PostRock included in Part II, Item 8 of this Annual Report on Form 10-K. We have derived the selected consolidated financial information of our predecessor as of December 31, 2008, 2007 and 2006 and for the years ended December 31, 2007 and 2006 from the predecessor s consolidated financial information included in its annual report on Form 10-K/A for the year ended December 31, 2008.

| | | Predecessor | | | | |
|---|---|---|---|---|---|---|
| | March 6 to December 31, 2010 | January 1 to March 5, 2010 | Years Ended December 31, 2009 | 2008 | 2007 | 2006 |
| | (In thousands, except per share data) | | | | | |
| **Statement of Operations Data** | | | | | | |
| Revenues | | | | | | |
| Oil and gas sales | $ 69,277 | $ 18,659 | $ 79,893 | $ 162,499 | $ 105,285 | $ 72,410 |
| Gathering revenue | 4,771 | 1,076 | 7,760 | 8,704 | 6,667 | 5,014 |
| Pipeline revenue | 8,380 | 1,749 | 18,428 | 19,472 | 3,186 | |
| Total revenues | 82,428 | 21,484 | 106,081 | 190,675 | 115,138 | 77,424 |
| Costs and expenses | | | | | | |
| Oil and gas production | 38,329 | 8,645 | 55,961 | 66,218 | 56,299 | 38,489 |
| Interstate pipeline operating | 5,195 | 1,110 | 6,573 | 7,635 | 1,094 | |
| General and administrative | 20,705 | 5,735 | 41,723 | 28,269 | 21,023 | 8,655 |
| Depreciation, depletion and amortization | 18,683 | 4,164 | 47,802 | 70,445 | 39,782 | 27,011 |
| (Gain) loss on sale of assets | (13,495) | | 25 | (24) | 322 | (3) |
| Impairments | | | 268,630 | 298,861 | | |
| Loss (recovery) from misappropriation of funds | (1,592) | | (3,412) | | 2,000 | 6,000 |
| Total costs and expenses | 67,825 | 19,654 | 417,302 | 471,404 | 120,520 | 80,152 |
| Operating income (loss) | 14,603 | 1,830 | (311,221) | (280,729) | (5,382) | (2,728) |
| Other income (expense) | | | | | | |
| Gain from derivative financial instruments | 47,870 | 25,246 | 48,122 | 66,145 | 1,961 | 52,690 |
| Gain on forgiveness of debt | 2,909 | | | | | |
| Other income (expense) | (24) | (4) | 108 | 305 | (9) | 99 |
| Interest expense, net | (20,137) | (5,336) | (29,329) | (25,373) | (43,628) | (20,567) |
| Total other income and (expense) | 30,618 | 19,906 | 18,901 | 41,077 | (41,676) | 32,222 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Income (loss) before income taxes | 45,221 | 21,736 | (292,320) | (239,652) | (47,058) | 29,494 |
| Income tax expense | | | | | | |
| Net income (loss) | 45,221 | 21,736 | (292,320) | (239,652) | (47,058) | 29,494 |
| Net (income) loss attributable to noncontrolling interests | | (9,958) | 147,398 | 72,268 | 2,904 | 14 |
| Net income (loss) attributable to controlling interest | 45,221 | 11,778 | (144,922) | (167,384) | (44,154) | 29,508 |
| Preferred stock dividends and accretion | (2,307) | | | | | |
| Net income (loss) available to common shareholders | $ 42,914 | $ 11,778 | $ (144,922) | $ (167,384) | $ (44,154) | $ 29,508 |
| Net income (loss) available to common shareholders per share: | | | | | | |
| Basic | $ 5.29 | $ 0.37 | $ (4.55) | $ (6.20) | $ (1.97) | $ 1.33 |
| Diluted | $ 4.62 | $ 0.36 | $ (4.55) | $ (6.20) | $ (1.97) | $ 1.33 |
| **Balance Sheet Data (at end of period)** | | | | | | |
| Total assets | $ 296,812 | $ 310,234 | $ 283,655 | $ 650,176 | $ 672,537 | $ 467,936 |
| Other non-current liabilities | $ 13,831 | $ 17,148 | $ 15,121 | $ 10,152 | $ 9,249 | $ 12,288 |
| Long-term debt, net of current maturities | $ 209,721 | $ 20,251 | $ 19,295 | $ 343,094 | $ 233,046 | $ 225,245 |
| Redeemable Preferred Stock | $ 50,622 | $ | $ | $ | $ | $ |

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Comparability of information in the above table between years is affected by, among other things, (1) changes in the annual average prices for oil and natural gas, (2) increased production from drilling and development activity in 2007 and 2008 followed by a lack of development activity in 2009 due to liquidity constraints, (3) the acquisition of the KPC Pipeline on November 1, 2007, (4) the PetroEdge acquisition in July 2008, (5) investigation and litigation costs associated with the misappropriation in 2008 and 2009, (6) the Recombination in 2010 and expenses related to the Recombination in 2009 and 2010 and (7) impairment of production properties of $298.9 million in 2008 compared to $102.9 million in 2009 as well as impairment of long lived assets associated with our interstate and gathering pipelines of $165.7 million in 2009.

## ITEM 7. *MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

The following discussion should be read together with the consolidated financial statements and the notes to consolidated financial statements, which are included in Part II, Item 8 of this Annual Report on Form 10-K, and the Risk Factors, which are included in Part I, Item 1A of this Annual Report on Form 10-K.

Where presented in this Item 7 and Item 7A, financial information for the 2010 year includes our predecessor for the period from January 1, 2010 through March 5, 2010 and PostRock for the period from March 6, 2010 through December 31, 2010.

### Overview of Our Company

We are an independent oil company engaged in the acquisition, exploration, development, production and gathering of crude oil and natural gas. We manage our business in two segments, production and pipeline.

Our production segment is focused in the Cherokee Basin, a 15-county region in southeastern Kansas and northeastern Oklahoma. We also have minor oil producing properties in Oklahoma and certain other minor gas producing properties in the Appalachian Basin.

Our pipeline segment consists of a 1,120 mile interstate natural gas pipeline, which transports natural gas from northern Oklahoma and western Kansas to Wichita and Kansas City. We acquired the KPC Pipeline in November 2007.

### Strategy

Our focus, particularly in the current challenging pricing environment, is on efficiently growing reserves and production, lowering costs and further reducing debt. Specifically, we are striving to become the most efficient producer in the Cherokee Basin area. We believe this strategy can be achieved through our vertically integrated operating model which includes a full complement of fracture treating and well servicing equipment, and utilizes the latest artificial lift and well management system technology. We are also working to increase the amount of gas being transported on our pipeline, thereby creating capacity constraints that we believe will lead to long-term firm transportation agreements. When appropriate, we intend to pursue opportunistic acquisitions that are accretive to our existing operations.

### Financial and Operating Highlights

Our significant highlights in 2010 include:

- recombined our predecessor entities to form PostRock Energy Corporation;

completed a $60 million White Deer investment;

closed the first phase of our Appalachia Basin asset sale in December 2010 and the second phase in January 2011 for a combined $39.7 million;

increased capital spending to $28.1 million as compared with $8.4 million in 2009;

completed and connected 163 new natural gas and oil wells in the Cherokee Basin and returned 292 wells in the basin to production;

restructured and simplified our credit agreements to reduce borrowing costs, extend maturities, and improve covenants;

decreased debt by $109.1 million from December 31, 2009 with another $9.3 million of principal reduction in January 2011 utilizing proceeds from the second phase of the Appalachia sale;

generated net income available to common stockholders of $54.7 million as compared with a net loss of $144.9 million for 2009;

generated gains on derivative financial instruments of $73.1 million (including unrealized mark-to-market gains of $41.1 million) as compared with gains of $48.1 million (including unrealized mark-to-market losses of $50.0 million) for 2009; and

increased total liquidity to $37.2 million as of December 31, 2010, consisting of year-end cash balances plus funds available under credit facilities, as compared with $20.9 million at December 31, 2009.

**Material Events and Transactions During 2010**

***Recombination***

The Recombination closed on March 5, 2010. The Recombination allowed us to begin to reduce general and administrative costs and facilitated the successful restructuring of our credit facilities, allowing us to implement an enhanced development plan for our production assets. See Note 1 in Part II, Item 8 of this Annual Report on Form 10-K for further details on the Recombination.

***White Deer Investment***

On September 21, 2010, White Deer purchased $60 million initial liquidation preference of our Series A Cumulative Redeemable Preferred Stock and 71/2 year warrants to purchase $60 million of our common stock at an exercise price of $3.15 per share. See *Liquidity and Capital Resources below* and Note 12 in Part II, Item 8 of this Annual Report on Form 10-K for further details about the securities issued as a result of White Deer s investment.

***Credit Restructuring***

Simultaneous with the equity investment described above, on September 21, 2010, our credit agreements were restructured and we repaid $58.9 million of our debt. The restructuring resulted in more favorable debt covenants, borrowing base provisions and interest rates for our credit facilities while permitting us to further simplify our organizational structure. See *Liquidity and Capital Resources* below for a description of our restructured credit facilities.

***Appalachian Basin Asset Sale***

In December 2010, we entered into an agreement with MHR to sell to MHR certain oil and gas properties and related assets located in Wetzel and Lewis Counties, West Virginia. The sale enabled us to reduce debt and focus on the Cherokee Basin. The sale closed in two phases for $39.7 million. The first phase covered assets located in Wetzel County which closed in December 2010 for $28 million. The second phase covered assets located in Lewis County which closed in January 2011 for $11.7 million. The amount received at both closings was paid half in cash and half in MHR common stock. See Part I. Item 1 *Business* *Business Segments* *Production* *Appalachian Basin Asset Sale* for further details on the transaction.

**How We Evaluate Our Operations**

Management uses and expects to continue to use a variety of financial and operational measurements to analyze performance and the health of the business. These measurements focus on rates of return, cost efficiency and cost reductions. Specifically we manage our: (1) volumes produced; (2) quantity of proved reserves; (3) realized prices; (4) gathering throughput volumes, fuel consumption by our facilities and natural

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gas sales volumes; (5) firm transportation contracted volumes; and (5) lease operating expense, gathering expense, interstate pipeline operating expense, and general and administrative expense.

## General Trends and Outlook

### *Realized Prices*

We are affected by the overall price levels for oil and natural gas, the volatility of these prices and the basis differential from NYMEX pricing to our sales point pricing. According to the U.S. Energy Information Administration ( EIA ), the Henry Hub spot price averaged $4.39 per Mcf in 2010, and the forecast price averages $4.02 per Mcf in 2011 and $4.50 per Mcf in 2012. Oil and natural gas prices historically have been very volatile and will likely continue to be so in the future.

We sell the majority of our gas in the Cherokee Basin based on the Southern Star first of month index, with the remainder sold on the daily price on the Southern Star index. We sell the majority of our natural gas in the Appalachian Basin based on the Dominion Southpoint index, with the remainder sold on local basis. We sell the majority of our oil production under a contract priced at a fixed discount to NYMEX oil prices. The Southern Star prices typically are at a discount to the NYMEX pricing at Henry Hub, the regional pricing point, whereas Appalachian prices typically are at a premium to NYMEX pricing. During 2010, the discount (or basis differential) in the Cherokee Basin ranged from $(0.44)/Mmbtu to $0.05/Mmbtu. Due to the historical volatility of oil and natural gas prices, we implemented a hedging strategy aimed at reducing the variability of prices we receive for the sale of our future production. See Part II, Item 7A *Quantitative and Qualitative Disclosures About Market Risk* of this Annual Report on Form 10-K for further details on our hedging activity.

### *Supply and Demand of Oil and Gas*

The EIA estimates that total natural gas consumption increased by 5.5 percent in 2010, as the economy began its recovery from the economic downturn. However, total annual natural gas consumption is forecasted to decline in 2011 as a result of fewer heating degree-days during the winter months this year as well as lower consumption in the electric power sector because of the forecast return to near-normal summer weather compared with the very warm summer last year. Driven by growth in the electric power and industrial sectors, total natural gas consumption is expected to grow by 1.6 percent in 2012 to 66.5 billion cubic feet per day (Bcf/d). Total marketed natural gas production increased significantly in 2010, by an estimated 2.4 Bcf/d, or 4.1 percent. Declines in production of 0.07 Bcf/d and 0.46 Bcf/d in Alaska and the Gulf of Mexico, respectively, were offset by a 2.9 Bcf/d increase in lower-48 onshore production. EIA expects average total production to fall by 0.3 percent in 2011 driven by a falling drilling rig count in response to lower prices. The large price difference between petroleum liquids and natural gas on an energy-equivalent basis is expected to contribute to a shift towards drilling for liquids. The projected decline in natural gas production in 2011 and increase in natural gas consumption in 2012 are expected to contribute to a strengthening of natural gas prices late in 2011 and in 2012. As natural gas prices begin to rise, forecasted production is expected to increase by 2.2 percent in 2012.

EIA expects a continued tightening of world oil markets over the next two years. World oil consumption is expected to grow by an annual average of 1.5 million barrels per day (bbl/d) through 2012 while the growth in supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries is expected to average less than 0.1 million bbl/d each year. The market is expected to rely on both inventories and significant increases in production of crude oil and non-crude liquids in OPEC member countries to meet world demand growth. There are many significant uncertainties that could push oil prices higher or lower than expected. Should OPEC not increase production as global consumption recovers, oil prices could be significantly higher than the central forecast. The rate of economic recovery, both domestically and globally, also remains uncertain due to a variety of factors including fiscal issues facing national and sub-national governments, China s efforts to address concerns regarding its growth and inflation rates, and unforeseen production issues. The projected WTI spot price is expected to average $93 per barrel in 2011 and $98 per barrel in 2012.

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### *Drilling Programs*

As a result of the global economic and financial crisis, weak commodity prices, the unauthorized transfers of funds by prior senior management and restrictions in our credit agreements, we were not able to raise the capital necessary to implement drilling programs for 2009 and most of 2010. Our liquidity constraints limited us to drilling and completing five wells in 2009 and completing 163 wells in 2010, of which 124 were drilled prior to 2010. Although the majority of our project work in the first half of the year was delivered on schedule and under budget, a number of wells did not achieve peak production rate as expected. To better understand the geology and fracture treatments required in the different areas of the Cherokee Basin we have compiled detailed engineering data and we are continuing to collect data and to perform studies of this data. Based on preliminary findings, we are evaluating the possibility of finding more conventional gas reserves in other geologic zones. Individual well results from the wells drilled in the third and fourth quarter have been mixed, but on the whole these wells are meeting cumulative production targets as budgeted. We continue to further refine our understanding of the geoscience in the Cherokee Basin to improve individual well results.

For 2011, we have budgeted approximately $43.6 million to drill and complete 290 new wells, complete eight previously drilled wells and recomplete 40 wells in the Cherokee Basin. We intend to fund these capital expenditures with available cash from operations after taking into account our debt service obligations. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, gas prices, costs and drilling results. See Item 1A. *Risk Factors Risks Related to Our Business Our identified drilling location inventories will be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our results of operations.*

## Results of Operations

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| | | (In thousands) | |
| Revenues | | | |
| Oil and natural gas sales | $ 87,936 | $ 79,893 | $ 162,499 |
| Gathering revenue | 5,847 | 7,760 | 8,704 |
| Total production segment | 93,783 | 87,653 | 171,203 |
| Pipeline segment | 10,129 | 18,428 | 19,472 |
| Total revenues | $ 103,912 | $ 106,081 | $ 190,675 |
| Operating profit (loss) | | | |
| Production(1) | $ 40,972 | $ (222,839) | $ (254,221) |
| Pipeline(2) | 309 | (50,071) | 1,761 |
| Total operating profit (loss) | 41,281 | (272,910) | (252,460) |
| General and administrative expenses | 26,440 | 41,723 | 28,269 |
| Recovery of misappropriation funds | (1,592) | (3,412) | |
| Total operating income (loss) | $ 16,433 | $ (311,221) | $ (280,729) |

(1) Includes impairment of production properties of $215.1 million and $298.9 million in 2009 and 2008, respectively. The impairment of $215.1 million in 2009 includes the impairment of our gathering system of $112.2 million.

(2) Includes impairment of our pipeline assets of $53.6 million in 2009.

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**Year ended December 31, 2010 compared to the year ended December 31, 2009**

The following table presents financial and operating data for our production and pipeline segments for the fiscal years ended December 31, 2010 and 2009.

| | Year Ended December 31, 2010 | Year Ended December 31, 2009 | Increase/ (Decrease) | |
|---|---|---|---|---|
| | ($ in thousands except per unit data) | | | |
| **Production Segment** | | | | |
| Oil and gas sales | $ 87,936 | $ 79,893 | $ 8,043 | 10.1% |
| Gathering revenue | $ 5,847 | $ 7,760 | $ (1,913) | (24.7)% |
| Production operating costs | $ 46,974 | $ 55,961 | $ (8,987) | (16.1)% |
| Depreciation, depletion and amortization | $ 19,409 | $ 39,438 | $ (20,029) | (50.8)% |
| Gain (loss) on sale of assets | $ 13,572 | $ (25) | $ 13,597 | 543.9% |
| Impairment | $ | $ 215,068 | $ (215,068) | *% |
| **Production Data** | | | | |
| Total production (Mmcfe) | 19,685 | 21,733 | (2,048) | (9.4)% |
| Average daily production (Mmcfe/d) | 53.9 | 59.5 | (5.6) | (9.4)% |
| **Average Sales Price per Unit (Mcfe)** | $ 4.47 | $ 3.68 | $ 0.79 | 21.5% |
| **Average Unit Costs per Mcfe** | | | | |
| Production operating costs | $ 2.39 | $ 2.58 | $ (0.19) | (7.4)% |
| Depreciation, depletion and amortization | $ 0.99 | $ 1.81 | $ (0.82) | (45.3)% |
| **Pipeline Segment** | | | | |
| Pipeline revenue | $ 10,129 | $ 18,428 | $ (8,299) | (45.0)% |
| Pipeline operating expense | $ 6,305 | $ 6,573 | $ (268) | (4.1)% |
| Depreciation and amortization expense | $ 3,438 | $ 8,364 | $ (4,926) | (58.9)% |
| Loss on sale of assets | 77 | | 77 | *% |
| Impairment | $ | $ 53,562 | $ (53,562) | *% |

* Not meaningful

*Oil and Gas Sales* Oil and gas sales increased $8.0 million, or 10.1%, to $87.9 million for the year ended December 31, 2010 from $79.9 million for the year ended December 31, 2009. An increase in average realized sales prices resulted in a $15.6 million increase in revenue while the reduction in volumes resulted in a $7.6 million decrease. Oil and gas sales exclude hedge settlements.

*Gathering Revenue* Gathering revenue decreased $1.9 million, or 24.7%, to $5.9 million during the year ended December 31, 2010, from $7.8 million during the year ended December 31, 2009. The decrease was a result of a lower contracted transportation rate as well as lower volumes transported.

*Pipeline Revenue* Pipeline revenue decreased $8.3 million, or 45.0%, to $10.1 million during the year ended December 31, 2010, from $18.4 million during the year ended December 31, 2009. The decrease was primarily due to the expiration of a significant firm transportation contract in October 2009.

*Production Operating Costs* Production operating costs consist of lease operating expenses, severance and ad valorem taxes and gathering expense. Production operating costs decreased $9.0 million, or 16.1%, to $47.0 million during the year ended December 31, 2010, from $56.0 million during the year ended December 31, 2009. The decrease was due to lower ad valorem taxes of $3.0 million, lower lease operating expenses of $4.0 million and lower gathering expense of $2.6 million partially offset by an increase in severance taxes of $0.6 million. Ad valorem taxes were assessed lower during 2010 primarily due to lower prices and the lack of a drilling program during 2009 and 2010. Lease operating expenses decreased as a result of lower labor costs and lower costs for repairs and maintenance. Gathering expense was lower primarily due to lower compression costs. Production operating costs per Mcfe decreased $0.19, or 7%, to $2.39 per Mcfe during the year ended December 31, 2010, from $2.58 per Mcfe during the year ended December 31, 2009.

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*Pipeline Operating Expense* Pipeline operating expense was generally flat, decreasing $0.3 million, or 4.1%, to $6.3 million during the year ended December 31, 2010, from $6.6 million during the year ended December 31, 2009.

*Production Segment Depreciation, Depletion and Amortization* We are subject to variances in our depletion rates from period to period due to changes in our oil and gas reserve quantities, production levels, product prices and changes in the depletable cost basis of our oil and gas properties. Our depreciation, depletion and amortization decreased approximately $20.1 million, or 50.8%, during the year ended December 31, 2010, to $19.4 million from $39.5 million during the year ended December 31, 2009. On a per unit basis, we had a decrease of $0.82 per Mcfe to $0.99 per Mcfe during the year ended December 31, 2010, from $1.81 per Mcfe during the year ended December 31, 2009. The amounts above include depreciation associated with our gathering system which was reclassified from our pipeline segment to our production segment during the fourth quarter of 2010. Prior to the reclassification, depreciation on the gathering system during the first three quarters of 2010 was $3.2 million lower than the comparable period in 2009. The decrease was a result of the impairment recorded during the fourth quarter of 2009 which lowered the depreciable basis of that asset. Absent depreciation from our gathering system, depreciation, depletion and amortization also decreased due to lower production and a lower depletion rate. Our depletion rate was lower in 2010 as a result of an increase in proved reserves relative to the prior year.

*Pipeline Depreciation and Amortization* Depreciation and amortization expense decreased $4.9 million, or 58.9%, to $3.5 million during the year ended December 31, 2010, from $8.4 million during the year ended December 31, 2009. The decrease was due to an impairment charge of $53.6 million recorded during the fourth quarter of 2009, which subsequently lowered the depreciable basis of these assets.

*Production Segment Gain (loss) on Sale of Assets* Gain from the sale of assets of $13.5 million during the year ended December 31, 2010 was primarily due to the first phase of the Appalachian Basin asset sale in December 2010.

*Impairment of Production Properties* We recorded impairments of our production properties of $215.1 million for 2009 while no impairment was recorded in 2010. Our impairment in 2009 included $102.9 million during the first quarter of 2009 as a result of the ceiling test and $112.2 million during the fourth quarter of 2009 related to our gathering system assets prior to their reclassification into the full cost pool during 2010. Our gathering system impairment resulted from a reduction in projected future gathering revenues partially the result of capital expenditure limits contained in our former credit facilities.

*Impairment of Pipeline Assets* During the fourth quarter of 2009, we recorded an impairment of $53.6 million on our pipeline assets and related contract intangibles. No such impairment was required in 2010. The impairment in 2009 was a result of the expiration of a significant firm transportation contract in October 2009.

*General and Administrative Expenses* General and administrative expenses decreased $15.3 million, or 36.6%, to $26.4 million during the year ended December 31, 2010, from $41.7 million during the year ended December 31, 2009. Legal, accounting, consulting fees and fees paid to financial advisors decreased as a result of the completion of the reaudit and restatement of previously issued financial statements and the Recombination. The decreases from 2009 were partly offset by federal securities lawsuits settlement costs of $1.4 million and costs to refinance our debt. See Part I, Item 3 *Legal Proceedings* of this Annual Report on Form 10-K for further discussion of the settlement costs.

*Gain from Derivative Financial Instruments* Gain from derivative financial instruments increased $25.0 million to $73.1 million during the year ended December 31, 2010, from a gain of $48.1 million during the year ended December 31, 2009. We recorded a $41.2 million unrealized gain and a $31.9 million realized gain on our derivative contracts for the year ended December 31, 2010, compared to a $50.0 million unrealized loss and a $98.1 million realized gain for the year ended December 31, 2009. The decrease in realized gain was the result of contracts with higher settlement prices and a one-time gain of $26 million when we exited certain contracts in order to pay down debt in 2009.

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*Gain on Forgiveness of Debt* We recorded a gain on forgiveness of debt of $2.9 million for the year ended December 31, 2010. See *Liquidity and Capital Resources Credit Agreements* below for a discussion of our troubled debt restructuring.

*Interest Expense, Net* Interest expense, net, decreased $3.9 million, or 13.1%, to $25.5 million during the year ended December 31, 2010, from $29.4 million during the year ended December 31, 2009. The decrease was primarily the result of repayments of debt and lower interest rates on our restructured credit facilities.

*Recovery of Misappropriated Funds* We recorded a recovery of misappropriated funds of $1.6 million during the year ended December 31, 2010, compared to $3.4 million during the year ended December 31, 2009. These amounts represent recoveries of funds misappropriated between 2005 and 2007 by former officers.

**Year ended December 31, 2009 compared to the year ended December 31, 2008**

The following table presents financial and operating data for our production and pipeline segments for the fiscal years ended December 31, 2009 and 2008.

| | Year Ended December 31, 2009 | Year Ended December 31, 2008 | Increase/ (Decrease) | |
|---|---|---|---|---|
| | ($ in thousands except per unit data) | | | |
| **Production Segment** | | | | |
| Oil and gas sales | $ 79,893 | $ 162,499 | $ (82,606) | (50.8)% |
| Gathering revenue | $ 7,760 | $ 8,704 | $ (944) | (10.8)% |
| Production operating costs | $ 55,961 | $ 66,218 | $ (10,257) | (15.5)% |
| Depreciation, depletion and amortization | $ 39,438 | $ 60,369 | $ (20,931) | (34.7)% |
| Impairment | $ 215,068 | $ 298,861 | $ (83,793) | (28.0)% |
| **Production Data** | | | | |
| Total production (Mmcfe) | 21,733 | 21,748 | (15) | (0.1)% |
| Average daily production (Mmcfe/d) | 59.5 | 59.4 | 0.1 | 0.2% |
| **Average Sales Price per Unit (Mcfe)** | $ 3.68 | $ 7.47 | $ (3.79) | (50.7)% |
| **Average Unit Costs per Mcfe** | | | | |
| Production operating costs | $ 2.58 | $ 3.04 | $ (0.46) | (15.1)% |
| Depreciation, depletion and amortization | $ 1.81 | $ 2.78 | $ (0.97) | (34.9)% |
| **Pipeline Segment** | | | | |
| Pipeline revenue | $ 18,428 | $ 19,472 | $ (1,044) | (5.4)% |
| Pipeline operating expense | $ 6,573 | $ 7,635 | $ (1,062) | (13.9)% |
| Depreciation and amortization expense | $ 8,364 | $ 10,076 | $ (1,712) | (17.0)% |
| Impairment | $ 53,562 | $ | $ 53,562 | *% |

* Not meaningful

*Oil and Gas Sales* Oil and gas sales decreased $82.6 million, or 50.8%, to $79.9 million for the year ended December 31, 2009 from $162.5 million for the year ended December 31, 2008. A decrease in average realized sales prices decreased revenues by $82.5 million and a decrease in volumes resulted in an additional $0.1 million decrease. Oil and natural gas sales exclude hedge settlements.

*Gathering Revenue* Gathering revenue decreased $0.9 million, or 10.8%, to $7.8 million during the year ended December 31, 2009, from $8.7 million during the year ended December 31, 2008. The decrease was primarily a result of lower transported volumes in the Cherokee Basin.

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*Pipeline Revenue* Pipeline revenue decreased $1.0 million, or 5.4%, to $18.4 million during the year ended December 31, 2009, from $19.4 million during the year ended December 31, 2008. The decrease was primarily due to the expiration of a significant firm transportation contract in October 2009 as well as a renewal of certain other contracts at lower volumes and rates.

*Production Operating Cost* Production operating costs consist of lease operating expenses, severance and ad valorem taxes, and gathering expense. Production operating costs decreased $10.3 million, or 15.5%, to $56.0 million during the year ended December 31, 2009, from $66.3 million during the year ended December 31, 2008. This decrease was achieved through process improvement initiatives, the employment of the latest artificial lift technology in order to improve equipment reliability and minimize costly wellbore interventions and by optimizing our compression fleet to decrease fuel consumption and improve horsepower utilization. Operating cost were $2.58 per Mcfe for the year ended December 31, 2009, as compared to $3.04 per Mcfe for the year ended December 31, 2008.

*Pipeline Operating Expense* Pipeline operating expense decreased $1.1 million, or 13.9%, to $6.6 million during the year ended December 31, 2009, from $7.7 million during the year ended December 31, 2008. The decrease was a result of our cost-cutting efforts initiated in the third quarter of 2008 and continuing through 2009.

*Production Segment Depreciation, Depletion and Amortization* We are subject to variances in our depletion rates from period to period due to changes in our oil and gas reserve quantities, production levels, product prices and changes in the depletable cost basis of our oil and gas properties. Included in our production segment depreciation, depletion and amortization is depreciation on our gathering system whose assets were reclassified into full cost pool in the fourth quarter of 2010. Prior to the reclassification, our gathering system assets were depreciated under the straight-line method. Our depreciation, depletion and amortization decreased approximately $20.9 million, or 34.7%, during the year ended December 31, 2009 to $39.5 million from $60.4 million during the year ended December 31, 2008. On a per unit basis, we had a decrease of $0.97 per Mcfe to $1.81 per Mcfe during the year ended December 31, 2009, from $2.78 per Mcfe during the year ended December 31, 2008. This decrease was primarily due to the impairments of our properties in the fourth quarter of 2008 and the first quarter of 2009, which decreased our rate per unit, as well as the resulting decrease in the depletable pool.

*Pipeline Segment Depreciation and Amortization* Depreciation and amortization expense decreased $1.7 million, or 17.0%, to $8.4 million during the year ended December 31, 2009, from $10.1 million during the year ended December 31, 2008. The decrease was primarily due to a decrease in the amortization of contract related intangible assets associated with the pipeline.

*Impairment of Production Properties* We recorded an impairment of our production properties of $102.9 million during the first quarter of 2009 as a result of a ceiling test write-down triggered by depressed prices. In addition, we recorded an impairment of long-lived assets on our gathering system of $112.2 million during the fourth quarter of 2009. Our gathering system impairment resulted from a reduction in projected future gathering revenues partially the result of capital expenditure limits contained in our former credit facilities. The impairment charges in the first and fourth quarter of 2009 totaled $215.1 million. We recorded impairments of our oil and natural gas properties of $298.9 million for 2008.

*Impairment of Pipeline Assets* During the fourth quarter of 2009, we recorded an impairment of $53.6 million on our pipeline assets and related intangibles. The impairment was a result of the expiration of a significant firm transportation contract in October 2009, which we were unable to renew. No such impairment was required in 2008.

*General and Administrative Expenses* General and administrative expenses increased $13.4 million, or 47.6%, to $41.7 million during the year ended December 31, 2009, from $28.3 million during the year ended December 31, 2008. The increase is primarily due to the increased legal, consulting and audit fees due to the reaudits and restatements of our financial statement as well as increased legal, investment banker, and other professional fees in connection with our recombination activities.

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*Gain from Derivative Financial Instruments* Gain from derivative financial instruments decreased $18.0 million to $48.1 million during the year ended December 31, 2009, from a gain of $66.1 million during the year ended December 31, 2008. We recorded a $50.0 million unrealized loss and a $98.1 million realized gain on our derivative contracts for the year ended December 31, 2009, compared to a $72.5 million unrealized gain and a $6.3 million realized loss for the year ended December 31, 2008. The increase in realized gain included a one-time gain of $26 million as a result of amending or exiting certain above-market derivative financial instruments, in June 2009, in order to pay down debt.

*Interest Expense, Net* Interest expense, net, increased $3.9 million, or 15.6%, to $29.3 million during the year ended December 31, 2009, from $25.4 million during the year ended December 31, 2008. The increase is primarily due to $3.5 million in write-offs of unamortized debt issuance cost associated with the modification of our credit agreements in 2009.

*Recovery of Misappropriated Funds* As discussed above, we recorded a recovery of misappropriated funds of $3.4 million for 2009. There was no such recovery in 2008.

**Liquidity and Capital Resources**

***Historical Cash Flows and Liquidity***

*Cash Flows from Operating Activities* Cash flows from operating activities have historically been driven by the quantities of our production and the prices received from the sale of this production, and from our pipeline revenue. Prices of oil and gas have historically been very volatile and can significantly impact the cash from the sale our production. Use of derivative financial instruments help mitigate this price volatility. Cash expenses also impact our operating cash flow and consist primarily of production operating costs, severance and ad valorem taxes, interest on our indebtedness and general and administrative expenses.

Cash flows from operations totaled $38.8 million for the year ended December 31, 2010, as compared to $74.6 million and $61.9 million for the years ended December 31, 2009 and 2008, respectively. The decrease from 2009 to 2010 is attributable primarily to a decrease in realized gains on our derivatives offset by a smaller decrease in accounts payable compared to the prior year. The decrease in realized derivative gain was the result of contracts with higher settlement prices and a one-time gain of $26 million in 2009 when we exited certain contracts in order to pay down debt. The increase in cash flows from operations from 2008 to 2009 is attributable primarily to an increase in realized gains on our derivatives offset by lower revenues both due to depressed oil and natural gas prices in 2009.

*Cash Flows from Investing Activities* Cash flows from investing activities have historically been driven by sales of oil and gas properties, leasehold acquisitions, exploration and development and acquisitions of businesses. Net cash used in investing activities totaled $13.4 million for the year ended December 31, 2010, as compared to cash from investing activities of $0.3 million for the year ended December 31, 2009, and cash used of $266.6 million for the year ended December 31, 2008. Cash used in investing activities in 2010 was a result of $28.1 million of capital expenditures offset by $14.1 million in cash received primarily from the first phase of our Appalachian Basin asset sale in December 2010. Cash from investing activities was minimal in 2009 compared to prior years as we had significantly pared down our acquisition and development related capital

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expenditures in response to liquidity constraints in 2009. Cash used in investing activities in 2008 of $266.6 million was primarily driven by our significant development program during that year and our acquisition of oil and gas properties in the Appalachian Basin. The following table sets forth our capital expenditures, including costs we have incurred but not paid for the periods presented.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| | (In thousands) | | |
| **Capital expenditures** | | | |
| Leasehold acquisition | $ 2,192 | $ 1,998 | $ 18,945 |
| Exploration | | 128 | 1,273 |
| Development | 27,396 | 6,244 | 84,328 |
| Acquisition of PetroEdge | | | 142,618 |
| Acquisition of Seminole County, Oklahoma property | | | 9,500 |
| Pipeline | 1,362 | 678 | 1,391 |
| Other items (primarily capitalized overhead and interest) | 1,370 | 511 | 9,061 |
| Total capital expenditures | $ 32,320 | $ 9,559 | $ 267,116 |

*Cash Flows from Financing Activities* Cash flows from financing activities have historically been driven by borrowing and repayments on debt instruments, issuances of common stock and the costs associated with these activities. Cash used in financing activities was $45.5 million for the year ended December 31, 2010, as compared to cash used of $67.8 million and cash provided of $211.8 million for the years ended December 31, 2009 and 2008, respectively. The cash used in 2010 was due to $102.0 million in repayments of bank borrowings and $6.5 million of debt and equity financing costs offset by $60.0 million of proceeds from the White Deer investment, discussed below, and $3.0 million of bank borrowings. The cash used in financing activities in 2009 was primarily due to debt repayment of $67.4 million and $4.7 million in debt amendment fees offset by $4.3 million in proceeds from debt. In 2008, cash was provided by an increase in borrowings of $214.2 million and proceeds from issuance of common stock of $84.8 million, partially offset by repayments of note borrowings of $59.8 million, $24.4 million of distributions to unitholders and $3.0 million in debt financing costs.

***White Deer Investment***

On September 21, 2010, White Deer purchased $60 million initial liquidation preference of our Series A Cumulative Redeemable Preferred Stock (the Series A Preferred Stock ) along with 71/2 year warrants to purchase $60 million of our common stock at an exercise price of $3.15 per share, which represents an approximate 5% premium to our closing stock price on September 1, 2010, the day before the transaction was publicly announced. The Series A Preferred Stock is entitled to a cumulative dividend of 12% per year on its liquidation preference, compounded quarterly. Prior to July 1, 2013, we can elect to pay dividends on the Series A Preferred Stock in cash. During this period, if such dividends are not paid in cash, the liquidation preference of the Series A Preferred Stock will increase by the amount of the dividend and we will issue additional warrants exercisable for a number of shares of our common stock equal to the amount of the dividend divided by the closing price of the common stock on the trading day prior to the dividend payment date. We elected not to pay cash dividends in the amount of $2.0 million that were accrued as of December 31, 2010, but instead chose to increase the liquidation preference on the Series A Preferred Stock by the same amount. Additional warrants to purchase 536,586 shares of our common stock at an exercise price of $3.69 were also issued. We are required to redeem the Series A Preferred Stock on March 21, 2018 at 100% of the liquidation preference. See Note 12 in Part II, Item 8 of this Annual Report for further details on the securities issued as a result of White Deer s investment. At December 31, 2010, the Series A Preferred Stock had a liquidation preference of $62.0 million, and there were outstanding warrants to purchase a total of 19,584,205 shares of common stock at a weighted average exercise price of $3.16.

### *Appalachian Basin Asset Sale*

On December 30, 2010, we closed the first phase of the sale of the Appalachian Basin assets to MHR for $28.0 million, consisting of $14.0 million in cash and 2.3 million shares of MHR common stock. Of the cash amount, $4.2 million was placed in escrow pursuant to the terms of the purchase agreement to cover indemnities and title defects. On January 14, 2011, we closed the second phase of the sale for $11.7 million consisting of $5.8 million in cash and 0.9 million shares of MHR common stock. Of the cash amount, $1.7 million was placed in escrow. The sale enabled us to reduce debt and focus on the Cherokee Basin. Included in the $39.7 million purchase price was approximately $36.7 million representing the purchase price of assets owned by our subsidiary, Quest Eastern Resource LLC ( QER ), pledged as collateral under the Third Amended and Restated Credit Agreement between QER, as borrower, and Royal Bank of Canada ( RBC ), as administrative and collateral agent and lender. Approximately $12.1 million of the net cash consideration and the share consideration received by QER pursuant to the purchase agreement (totaling 3.0 million shares) were paid to RBC in repayment of a portion of the term loan under that credit agreement and as consideration for the release of RBC s liens encumbering the assets sold, which resulted in payments to RBC of $21.2 million and $9.3 million in connection with the December 2010 closing and with the January 2011 closing, respectively.

### *Credit Agreements*

Simultaneous with the White Deer investment described above, on September 21, 2010, our credit agreements were restructured and we repaid $58.9 million of our debt. The restructuring resulted in more favorable debt covenants, borrowing base provisions and interest rates for our credit facilities while permitting us to further simplify our organizational structure.

#### *Former Credit Agreements*

Prior to the restructuring, we had the following four credit agreements:

(i) A term loan with an outstanding principal balance of approximately $125 million and no available capacity, secured by our assets owned by Quest Cherokee, LLC (the Quest Cherokee Loan );

(ii) A second lien senior term loan with an outstanding principal balance of approximately $30.2 million, secured by a second lien on our assets owned by Quest Cherokee, LLC (the Second Lien Loan );

(iii) A credit agreement with an outstanding principal balance of approximately $118.7 million secured by our assets owned by PostRock Midstream, LLC and Bluestem Pipeline, LLC, which included the Bluestem gas gathering system and the KPC Pipeline (the Midstream Loan ); and

(iv) A credit agreement with an outstanding principal balance of approximately $43.8 million, secured by our Appalachian assets owned indirectly by PostRock Energy Services Corporation ( PESC ) (the PESC Loan ).

The terms of our previous credit facilities and activity prior to the restructuring are described in Item 8. Financial Statement and Supplementary Data in our Annual Report on Form 10-K for the year ended December 31, 2009, and in Part I, Item 1 in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2010.

#### *New Credit Agreements*

As a result of the restructuring of our credit facilities, we now have the following three credit agreements (the New Credit Agreements ):

(i) A $350 million secured borrowing base revolving credit facility with an initial borrowing base of $225 million and outstanding borrowings of $187.0 million at December 31, 2010, secured by, among other things, a first lien on our Cherokee Basin exploration and production assets, certain producing Appalachian production assets and the Cherokee Basin gas gathering system and a second lien on our interstate natural gas transportation pipeline (the Borrowing Base Facility );

(ii) A term loan with a balance of $13.5 million at December 31, 2010, secured by, among other things, a first lien on our interstate natural gas transportation pipeline and a second lien on our Cherokee

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Basin exploration and production assets, certain producing Appalachian production assets and the Cherokee Basin gas gathering system (the Secured Pipeline Loan ); and

(iii) A term loan with a carrying amount of $19.7 million at December 31, 2010, secured by our assets owned by QER, which include certain producing and non-producing Appalachian properties and the Appalachian gas gathering system, and a pledge of the equity of QER (the QER Loan ).

*Borrowing Base Facility*

The Borrowing Base Facility with PESC and our subsidiary PostRock MidContinent Production, LLC ( PMP ), as borrowers, RBC as administrative and collateral agent, and the lenders party thereto is a secured borrowing base facility with an initial borrowing base of $225 million and is guaranteed by PostRock and certain of its subsidiaries.

Under the terms of the Borrowing Base Facility, PMP and PESC prepaid the outstanding indebtedness under the Quest Cherokee Loan in an amount equal to approximately $19.2 million. In consideration therefor, the lenders completely restructured the credit agreements relating to the Quest Cherokee Loan and the Second Lien Loan with the Borrowing Base Facility, partially restructured the Midstream Loan, and secured the Borrowing Base Facility with the same assets that secured the Quest Cherokee Credit Agreement and the Second Lien Loan Agreement (including the assets of PMP, which include all of the oil and natural gas exploration assets located in the Cherokee Basin and all of the oil and natural gas exploration assets located in the Appalachian basin that are not owned by QER) in addition to the Bluestem gathering pipeline system (which had formerly partially secured the Midstream Loan). See Note 10 in Part II, Item 8 in this Annual Report on Form 10-K for a summary of the material terms of the Borrowing Base Facility.

At March 1, 2011, the outstanding balance on the Borrowing Base Facility was $181.5 million with an additional $1.5 million in outstanding letters of credit, resulting in approximately $42.0 million of additional availability.

*Secured Pipeline Loan*

The Secured Pipeline Loan with PESC and PostRock KPC Pipeline, LLC ( KPC ) as borrowers, RBC as administrative and collateral agent, and the lenders party thereto is a $15 million term loan secured by a first lien on the KPC Pipeline and the other assets of KPC, and by a second lien on the assets on which the lenders under the Borrowing Base Facility have a first lien.

Under the terms of the Secured Pipeline Loan, PESC and KPC prepaid approximately $14.7 million of the outstanding indebtedness under the Midstream Loan in exchange for the assignment by the lenders under the Midstream Loan of approximately $89.0 million of the indebtedness owing under the Midstream Loan to the lenders under the Borrowing Base Facility. The remaining $15.0 million of such indebtedness was retained under the Secured Pipeline Loan. See Note 10 in Part II, Item 8 of this Annual Report on Form 10-K for a summary of the material terms of the Secured Pipeline Loan.

At March 1, 2011, the outstanding balance on the Secured Pipeline Loan was $12.5 million. A monthly installment payment of $500,000 is due in late March followed by 12 additional payments of $1.0 million each due monthly thereafter.

*QER Loan*

As part of the closing of our amended and restated credit facilities, PESC, QER and RBC entered into an assumption agreement whereby QER assumed all of PESC s rights and obligations as borrower under the PESC Loan. In addition, QER, as borrower, entered into the third amended and restated credit agreement with RBC in the amount of approximately $43.8 million. In connection therewith, RBC, the lender under the PESC Loan released PESC from any liability or obligation to repay amounts owing under the PESC Loan and all of the guarantors thereunder from their respective guarantees of the indebtedness owing under the PESC Loan and (except for QER) from their respective mortgages and security agreements. RBC also released the liens on all the collateral owned by PESC, other than the Appalachian assets owned by QER and the equity of QER;

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and agreed to reconvey the overriding royalty interests to their respective grantors (or their designees) at such time as the Appalachian assets or equity of QER are sold or all outstanding obligations under the credit agreement have been paid in full or otherwise deemed to have been satisfied. Accordingly, under the QER Loan, RBC has recourse only to QER, its assets and the equity of QER. See Note 10 in Part II, Item 8 of this Annual Report on Form 10-K for a summary of the material terms of the QER Loan.

On February 21, 2011, we amended the QER Loan to delay the date of the first interest payment. No interest payments are due prior to May 16, 2011. Subsequent to May 16, 2011, interest payments on LIBOR loans are due on the last day of each LIBOR interest period, in no event less than quarterly, and interest payments on Base Rate Loans are due at the end of each quarter, beginning June 30, 2011.

At March 1, 2010, the carrying amount on the QER Loan was $10.4 million with no additional availability.

In connection with the QER Loan, we entered into an asset sale agreement with RBC that allowed us to sell QER or its assets and, in the event the proceeds are not adequate to repay the QER Loan in full, we agreed to pay a portion of such shortfall in cash, stock or a combination thereof. As discussed under Appalachian Basin Asset Sale above, we received $36.7 million in gross proceeds on the sale of QER s assets pledged as collateral under the QER Loan and made repayments to RBC totaling $30.5 million in cash and MHR common stock. Approximately $5.4 million of cash consideration received on the sale of QER s assets at the first two closings have been placed in escrow pursuant to the purchase agreement to cover indemnities and title defects. The extent of indemnities or title defects would determine the amount of escrowed funds reconveyed back to MHR. Any remaining balance of escrowed funds upon termination of the escrow will be remitted to RBC or PostRock pursuant to the terms of the asset sale agreement between the parties.

The restructuring which resulted in the QER Loan is considered a troubled debt restructuring under accounting guidance. In accordance with the guidance, we evaluated the maximum possible future cash flows conveyable to RBC in satisfaction of the QER Loan. In evaluating future cash proceeds to RBC, we considered our proceeds already received from the sale of our Appalachian Basin assets to MHR, the remaining provisions under the purchase agreement governing the Appalachian Basin asset sale and estimated fees related to the sale. As our estimate of future cash flows was less than the principal value of the QER Loan, we reduced the carrying amount of the QER Loan by $2.9 million while recording a corresponding gain on troubled debt restructuring during the fourth quarter of 2010. Absent this reduction, the outstanding principal balance on the QER Loan was $22.6 million at December 31, 2010. See Note 10 in Part II, Item 8 of this Annual Report on Form 10-K for a discussion on the accounting provisions for troubled debt restructurings.

***Sources of Liquidity in 2011 and Capital Requirements***

We rely on our cash flows from operating activities as a source of internally generated liquidity. For the most recent two years, our cash flows from operating activities have been sufficient to fund our investing activities. Our long term ability to generate liquidity internally depends in part on our ability to hedge future production at attractive prices as well as ability to control operating expenses. We generated cash of $32 million and $98 million from settlements of our oil and gas derivatives during 2010 and 2009, respectively. During this time, our derivative contracts covered approximately 83% and 72% of our production in 2010 and 2009. The volume covered by outstanding contracts as a percentage of our current year production is 70% in 2011, 57% in 2012 and 46% in 2013. At this time, we believe that commodity prices are not at levels that warrant actively hedging. When prices improve, we intend to resume our hedging activity. To a lesser extent, we also rely on sale of our non-core production assets to internally generate liquidity. As discussed above, the sale of our Appalachia basin assets generated $28.0 million and $11.7 million in proceeds in December 2010 and January 2011, respectively.

Our liquidity has improved substantially since restructuring our debt and completing the White Deer investment. At March 1, 2011, we have $42.0 million of availability under our Borrowing Base Facility which we utilize as an external source of long and short term liquidity. An additional $30 million of additional capital

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may also be available from White Deer for acquisitions, an accelerated development program or other corporate purposes on mutually acceptable terms pursuant to our securities purchase agreement with White Deer.

For 2011, we have budgeted approximately $43.6 million to drill and complete 290 new wells, complete 8 wells drilled in 2010, and recomplete 40 wells in the Cherokee Basin. We have also budgeted $7.3 million for land and equipment capital expenditures. We expect to fund these capital expenditures internally from our cash flows from operations. See Item 1A. *Risk Factors Risks Related to Our Business Our identified drilling location inventories will be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our results of operations.*

The borrowing base under our Borrowing Base Facility is determined based on the value of our oil and natural gas reserves at forward prices. As such, our borrowing base can be adversely affected by downward fluctuations in future prices of oil and natural gas. There has been a significant decline in gas prices since the borrowing base was last determined. As a result, we currently expect the borrowing base to be reduced in connection with the redetermination effective as of July 31, 2011. Any reduction in the borrowing base will reduce our available liquidity, and, if the reduction results in the outstanding amount under the facility exceeding the borrowing base, we will be required to repay the deficiency within 30 days or in six monthly installments thereafter, at our election. Our ability to maintain an active drilling program is crucial towards replacing reserves that have been diminished though current production.

**Contractual Obligations**

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. The following table summarizes these commitments at December 31, 2010.

| | Payments Due by Period (In thousands) | | | | |
|---|---|---|---|---|---|
| | **Total** | **Less Than 1 Year** | **1-3 Years** | **4-5 Years** | **More Than 5 Years** |
| Borrowing Base Facility | $ 187,000 | $ | $ 187,000 | $ | $ |
| Secured Pipeline Loan | 13,500 | 10,500 | 3,000 | | |
| QER Loan | 19,721 | | 19,721 | | |
| Interest expense on bank credit facilities | 21,422 | 8,785 | 12,637 | | |
| Operating lease obligations | 13,133 | 7,178 | 3,240 | 1,661 | 1,054 |
| Total commitments | $ 254,776 | $ 26,463 | $ 225,598 | $ 1,661 | $ 1,054 |

**Off-Balance Sheet Arrangements and Letters of Credit**

At December 31, 2010, we did not have any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not exposed to any financing, liquidity, market, or credit risk that could arise if we had engaged in such activities. At December 31, 2010, we had $1.5 million in outstanding letters of credit under our Borrowing Base Facility.

**Critical Accounting Policies**

The preparation of our consolidated financial statements requires us to make assumptions and estimates that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. We base our estimates on historical experiences and various other assumptions that we believe are reasonable; however, actual results may differ. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

***Oil and Gas Reserves***

Our most significant financial estimates are based on estimates of proved oil and gas reserves. Proved reserves represent estimated quantities of oil and gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production, and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering, and production data and, the accuracy of reserves estimates is a function of the quality and quantity of available data, engineering and geologic interpretation, and judgment. In addition, as a result of changing market conditions, commodity prices and future development costs will change from year to year, causing estimates of proved reserves to also change. Estimates of proved reserves are key components of our most significant financial estimates involving our unevaluated properties, our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. Our reserves are estimated on an annual basis by independent petroleum engineers.

***Oil and Natural Gas Properties***

The method of accounting for oil and gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for oil and natural gas properties. Under the full cost method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our oil and gas properties are capitalized.

Oil and gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved oil and gas reserves. Estimation of proved oil and gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Holding all other factors constant, if proved oil and gas reserves were revised upward or downward, earnings would increase or decrease, respectively. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition would have a significant impact on the depreciation, depletion, and amortization rate.

Under the full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation ). We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion, and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of our full cost pool is a non-cash charge that reduces earnings and impacts stockholders equity in the period of occurrence and typically results in lower depreciation, depletion, and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date. The risk that we will be required to write down the carrying value of our oil and natural gas properties increases during a period when gas prices are depressed. In addition, a write-down may occur if estimates of proved reserves are substantially reduced or estimates of future development costs increase significantly.

Through the quarter ended September 30, 2009, the ceiling test was calculated using natural gas prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. Beginning with the quarter ended December 31, 2009, a twelve-month average price is used and adjusted for basis differentials. In addition, subsequent to the adoption of FASB ASC 400-20 *Retirement and Environmental Obligations-Asset Retirement Obligation*, the future cash outflows associated with settling

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asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purpose of the ceiling test calculation.

***Unevaluated Properties***

The costs directly associated with unevaluated properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base once determination has been made or upon expiration of a lease. Geological and geophysical costs associated with a specific unevaluated property are transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. Any impairment to unevaluated properties is transferred to the amortization base.

***Future Abandonment Costs***

We have significant legal obligations to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed, or developed. Liabilities for asset retirement obligations are recorded at fair value in the period incurred. Upon initial recognition of the asset retirement liability, the asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. Asset retirement costs included in the carrying amount of the related asset are subsequently allocated to expense as part of our depletion calculation. Additionally, increases in the discounted asset retirement liability resulting from the passage of time are recorded as lease operating expense.

Estimating the future asset retirement liability requires us to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. We use the present value of estimated cash flows related to our asset retirement obligations to determine the fair value. Present value calculations inherently incorporate numerous assumptions and judgments. These include the ultimate retirement and restoration costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement liability, a corresponding adjustment will be made to the carrying cost of the related asset.

We have not recorded any asset retirement obligations relating to our gathering systems as of December 31, 2010 and 2009 because we do not have any legal or constructive obligations relative to asset retirements of the gathering systems. We have recorded asset retirement obligations relating to the abandonment of our interstate pipeline assets (see discussion in Note 6 Asset Retirement Obligations to the consolidated financial statements included in this Annual Report on Form 10-K).

***Derivative Instruments***

Due to the historical volatility of oil and gas prices, we have implemented a hedging strategy aimed at reducing the variability of prices we receive for our production. Currently, we use collars, fixed-price swaps and fixed price sales contracts as our mechanism for hedging commodity prices. Our current derivative instruments are not accounted for as hedges for accounting purposes in accordance with FASB ASC 815 Derivatives and Hedging ( FASB ASC 815 ). As a result, we account for our derivative instruments on a mark-to-market basis, and changes in the fair value of derivative instruments are recognized as gains and losses which are included in other income and expense in the period of change. While we believe that the stabilization of prices and production afforded us by providing a revenue floor for our production is beneficial, this strategy may result in lower revenues than we would have if we were not a party to derivative instruments in times of rising natural gas prices. As a result of rising commodity prices, we may recognize additional charges to future periods; however, for the year ended December 31, 2010, we recognized a total gain on

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derivative financial instruments in the amount of $73.1 million, consisting of a $31.9 million realized gain and a $41.2 million unrealized gain. Our estimates of fair value are determined by the use of an option-pricing model that is based on various assumptions and factors including the time value of options, volatility, and closing NYMEX market indices.

***Income Taxes***

We record our income taxes using an asset and liability approach in accordance with the provisions of FASB Accounting Standards Codification ( FASB ASC ) 740 Income Taxes. We recognize deferred tax assets and liabilities for the expected future tax consequences of temporary differences (primarily intangible drilling costs and the net operating loss carry forward) between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under FASB ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2010 and 2009, a full valuation allowance was recorded against our deferred tax assets.

We have net operating loss ( NOL ) carryforwards that are available to reduce our U.S. taxable future income. Our ability to utilize NOL carryforwards to reduce our future federal taxable income and federal income tax is subject to various limitations under Internal Revenue Code ( IRC ) Section 382. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of our stock during any three year period resulting in an aggregate change of more than 50% in the beneficial ownership of our Company. We experienced ownership changes within the meaning of IRC Section 382 on November 14, 2005, March 5, 2010, and September 21, 2010 and are therefore subject to IRC Section 382 limitations on our NOL carryforwards. See Note 9 in Part II, Item 8 of this Annual Report on Form 10-K for further discussion of these limitations.

On January 1, 2007, we adopted the provisions of FASB ASC 740 regarding the criteria an individual tax position must meet in order to be recognized in the financial statements. FASB ASC 740 provides guidance on the measurement of the income tax benefit associated with uncertain tax positions, derecognition, classification, interest and penalties and financial statement disclosure. We regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed under FASB ASC 740. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest and penalties related to uncertain tax positions as income tax expense.

**Recent Accounting Pronouncements**

In January 2010, the FASB released Accounting Standards Update ( ASU ) 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements*. The update requires reporting entities to provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy established under FASB ASC 820. The update also requires separate presentation (on a gross basis rather than as one net number) about purchases, sales, issuances, and settlements within the reconciliation of activity in Level 3 fair value measurements. The guidance is effective for any fiscal period beginning after December 15, 2009, except for the requirement to separately disclose purchases, sales, issuances, and settlements, which will be effective for any fiscal period beginning after December 15, 2010. We adopted the provisions of this update relating to disclosure on movement of assets among Levels 1 and 2 beginning with the quarter ended March 31, 2010. Other than additional disclosure required by the update, there was no material impact on our financial statements.

In February 2010, the FASB released ASU 2010-09, *Subsequent Events (Topic 855): Amendments to Certain Recognition and Disclosure Requirements* which removed some contradictions between the requirements of GAAP and the SEC s filing rules. As a result, public companies will no longer have to disclose the date of their financial statements in both issued and revised financial statements. The amendments became effective upon issuance of the update and we adopted the provisions of this update beginning with the quarter ended March 31, 2010, with no material impact on our financial statements.

## ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.*

The discussion in this section provides information about the financial instruments we use to manage commodity price and interest rate volatility. All contracts are financial contracts, which are settled in cash and do not require the actual delivery of a commodity quantity to satisfy settlement.

### Commodity Price Risk

Our most significant market risk relates to the prices we receive for our oil and natural gas production. For example, NYMEX-WTI oil prices ranged from a high of $91.51 per barrel in December 2010 to $68.01 per barrel in May 2010, with an average of approximately $79.61 per barrel in 2010. Meanwhile, near month NYMEX natural gas futures prices ranged from a high of $6.01 per Mmbtu in January 2010 to a low of $3.29 per Mmbtu in October 2010, with an average of approximately $4.38 per Mmbtu in 2010. In light of the historical volatility of these commodities, we periodically have entered into, and expect in the future to enter into, derivative arrangements aimed at reducing the variability of the prices we receive for our production. At this time, we believe that commodity prices are not at levels that warrant actively hedging. When prices improve, we intend to resume our hedging activity.

We have used, and may continue to use, a variety of commodity-based derivative financial instruments, including collars, fixed-price swaps and basis protection swaps. Our fixed price swap and collar transactions are settled based upon either NYMEX prices or index prices at our main delivery points, and our basis protection swap transactions are settled based upon the index price of natural gas at our main delivery points. Settlement for our gas derivative contracts typically occurs in advance of our purchaser receipts.

While we believe that the oil and gas price derivative arrangements we enter into are important to our program to manage price variability for our production, we have not designated any of our derivative contracts as hedges for accounting purposes. We record all derivative contracts on the balance sheet at fair value, which reflects changes in prices. Both realized and unrealized gains and losses from settlements of or changes in fair values of our derivative contracts are currently recognized in other income (expense) as they occur. As a result, our current period earnings may be significantly affected by changes in fair value of our commodity derivative contracts. Changes in fair value are principally measured based on period-end forward prices compared to the contract price.

Gains and losses associated with derivative financial instruments related to gas and oil production were as follows for the years indicated (in thousands).

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Realized gain (loss) | $ 31,932 | $ 98,148 | $ (6,388) |
| Unrealized gain (loss) | 41,184 | (50,026) | 72,533 |
| Total gain from derivative financial instruments | $ 73,116 | $ 48,122 | $ 66,145 |

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The following table summarizes the estimated volumes, fixed prices and fair value attributable to oil and natural gas derivative contracts at December 31, 2010. There were no derivative contracts beyond 2013.

| | Year Ending December 31, 2011 | 2012 | 2013 | Total |
|---|---|---|---|---|
| | ($ in thousands, except volumes and per unit data) | | | |
| **Natural Gas Swaps** | | | | |
| Contract volumes (Mmbtu) | 13,550,302 | 11,000,004 | 9,000,003 | 33,550,309 |
| Weighted-average fixed price per Mmbtu | $ 6.80 | $ 7.13 | $ 7.28 | $ 7.04 |
| Fair value, net | $ 31,588 | $ 22,728 | $ 16,905 | $ 71,221 |
| **Natural Gas Basis Swaps** | | | | |
| Contract volumes (Mmbtu) | 8,549,998 | 9,000,000 | 9,000,003 | 26,550,001 |
| Weighted-average fixed price per Mmbtu | $ (0.67) | $ (0.70) | $ (0.71) | $ (0.69) |
| Fair value, net | $ (3,417) | $ (3,405) | $ (3,031) | $ (9,853) |
| **Crude Oil Swaps** | | | | |
| Contract volumes (Bbl) | 48,000 | 42,000 | | 90,000 |
| Weighted-average fixed price per Bbl | $ 85.90 | $ 87.90 | $ | $ 86.83 |
| Fair value, net | $ (375) | $ (245) | $ | $ (620) |
| **Total fair value, net** | **$ 27,796** | **$ 19,078** | **$ 13,874** | **$ 60,748** |

### Interest Rate Risk

Although none are currently outstanding, from time to time we may enter into interest rate derivatives to mitigate our exposure to fluctuations in interest rates on variable rate debt. As of December 31, 2010, we had outstanding $220.2 million of variable-rate debt. A 1% increase in our interest rates would increase gross interest expense approximately $2.2 million per year.

## ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.*

Please see the accompanying consolidated financial statements and related notes thereto beginning on page F-1.

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

None.

## ITEM 9A. *CONTROLS AND PROCEDURES*

**Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures**

Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and that such information is accumulated and communicated to management, including the principal executive officer and the principal financial officer, to allow timely decisions regarding required disclosures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

In connection with the preparation of this Annual Report on Form 10-K, our management, under the supervision and with the participation of our principal executive officer and principal financial officer, conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2010. Based on that evaluation, our principal executive officer and principal financial officer concluded that, as of December 31, 2010, our disclosure controls and procedures were effective with respect to the recording, processing, summarizing and reporting, within the time periods specified in the SEC s rules and forms, of information required to be disclosed by us in the reports that we file or submit under the Exchange Act.

**Management s Annual Report on Internal Control Over Financial Reporting**

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) 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 GAAP and includes those policies and procedures that (a) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of assets, (b) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, (c) provide reasonable assurance that receipts and expenditures are being made only in accordance with appropriate authorization of management and the board of directors, and (d) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of 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 connection with the preparation of this Annual Report on Form 10-K, our management, under the supervision and with the participation of our principal executive officer and principal financial officer, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework ). Based on the evaluation performed, we concluded that our internal control over financial reporting as of December 31, 2010 was effective based on the criteria set forth in the COSO Framework.

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**Changes in Internal Control Over Financial Reporting**

During 2009 and 2010, in order to address the material weaknesses in internal control over financial reporting disclosed in Item 9A of our Annual Report on Form 10-K for the year ended December 31, 2009 and in quarterly reports filed during 2010, we

(a) Appointed a new management team which, under the direction of the Board of Directors, was tasked with achieving and maintaining a strong control environment, high ethical standards, and financial reporting integrity. In May 2009, Mr. David Lawler was appointed Chief Executive Officer (our principal executive officer); in January 2010, Mr. Stephen DeGiusti was appointed General Counsel and Chief Compliance Officer, and in March 2010, Mr. Jack Collins was appointed Chief Financial Officer and Mr. David Klvac was appointed Chief Accounting Officer;

(b) Hired additional experienced accounting personnel with specific experience in (1) financial reporting for public companies; (2) preparation of consolidated financial statements; (3) oil and gas property and pipeline asset accounting; (4) inter-company accounts and investments in subsidiaries; and (5) revenue accounting;

(c) Implemented the practice of reviewing consolidating financial statements with senior management, the audit committee of the board of directors, and the full board of directors;

(d) Implemented a closing calendar and consolidation process that includes preparation of accrual-based financial statements, account reconciliations, inter-company accounts, and journal entries being reviewed by qualified personnel in a timely manner;

(e) Engaged a professional services firm to assist with the evaluation of derivative transactions, and designed and implemented controls and procedures related to the evaluation and recording of derivative transactions;

(f) Implemented additional training and/or increased supervision regarding the initiation, approval and reconciliation of cash transactions, and properly segregated the treasury and accounting functions related to cash management and wire transfers;

(g) Engaged a professional services firm to assist with conducting the evaluation of the design and implementation of the internal control environment to assist with identifying opportunities to improve the design and effectiveness of the control environment and to perform effectiveness testing of the control environment;

(h) Completed disclosure checklists for required disclosures under GAAP, SEC rules, and oil and gas accounting in an effort to ensure disclosures are complete in all material respects;

(i) Created a disclosure committee as part of our SEC filing process and began regular meetings during the third quarter of 2009;

(j) Improved internal communication with employees regarding ethics and the availability of our internal fraud hotline;

(k) Performed a preliminary assessment of accounting and disclosure policies and procedures and began the process of updating and revising those policies and procedures;

(l) Created a steering committee to monitor the progress of the evaluation of the internal controls and began regular meetings during the second quarter of 2010; and

(m) Created a policy aimed at standardizing the form, timing and authorization of stock based awards.

Our management concluded that, as of December 31, 2010, these changes in our internal control over financial reporting remediated the previously disclosed material weaknesses. Except for the remediation efforts discussed above, there was no change in our internal control over financial reporting that occurred during the fourth quarter of 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

**Auditor Attestation Report**

This Annual Report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting due to an exemption provided by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act ) enacted into law in July 2010. The Dodd-Frank Act provides smaller public companies and debt-only issuers with a permanent exemption from

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the requirement to obtain an external audit on the effectiveness of internal financial reporting controls provided in Section 404(b) of the Sarbanes-Oxley Act. PostRock is a smaller reporting company and is eligible for this exemption under the Dodd-Frank Act.

**ITEM 9B.** ***OTHER INFORMATION***

On February 24, 2011 and effective February 21, 2011, QER entered into an amendment to credit agreement with RBC providing for the QER Loan. The amendment delays the date on which the first interest payments under the QER Loan are due as follows: (1) interest payments on LIBOR loans will not be due until the last day of each interest period occurring after May 16, 2011, and (2) interest payments on base rate loans will not be due until the last day of each fiscal quarter beginning on June 30, 2011. The amendment also clarifies that one of the circumstances that would obligate the lenders to reconvey to our subsidiaries the overriding royalty interests that such subsidiaries have assigned to the lenders includes the deemed satisfaction, pursuant to the asset sale agreement between QER and RBC, of all outstanding obligations under such credit agreement. The amendment did not result in an increase in cash interest expense and no amendment fees were incurred in connection therewith. For a description of the QER Loan, see Note 10 in Part II, Item 8 in this Annual Report on Form 10-K.

## PART III

**ITEM 10.** ***DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE***

Information required by Part III, Item 10 is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

**ITEM 11.** ***EXECUTIVE COMPENSATION***

Information required by Part III, Item 11 is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

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

Information required by Part III, Item 12 is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

**ITEM 13.** ***CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE***

Information required by Part III, Item 13 is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

**ITEM 14.** ***PRINCIPAL ACCOUNTING FEES AND SERVICES***

Information required by Part III, Item 14 is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

## PART IV

### ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

*(a)(1) and (2)* Financial Statements See Index to Financial Statements set forth on page F-1 of this Annual Report on Form 10-K.

*(a)(3)* Index to Exhibits Exhibits requiring attachment pursuant to Item 601 of Regulation S-K are listed in the Index to Exhibits to this Annual Report on Form 10-K that is incorporated herein by reference.

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## Index to Financial Statements

**PostRock Energy Corporation**

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of PostRock Energy Corporation:

We have audited the accompanying consolidated balance sheet of PostRock Energy Corporation (the Company ) as of December 31, 2010 and the consolidated balance sheet of its Predecessor (as defined in Note 1 to the financial statements) as of December 31, 2009, and the related consolidated statements of operations, cash flows and equity of the Company for the period from March 6, 2010 to December 31, 2010 and of the Predecessor for the period from January 1, 2010 to March 5, 2010 and the years ended December 31, 2009 and 2008. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements 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 consolidated financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly we express no opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of PostRock Energy Corporation as of December 31, 2010 and of the Predecessor as of December 31, 2009, and the related consolidated statements of operations, cash flows and equity of the Company for the period from March 6, 2010 to December 31, 2010 and of the Predecessor for the period from January 1, 2010 to March 5, 2010 and the years ended December 31, 2009 and 2008, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas
March 3, 2011

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED BALANCE SHEETS**

| | December 31, 2010 | December 31, 2009 (Predecessor) |
|---|---|---|
| | ($ in thousands, except share and per share data) | |
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 730 | $ 20,884 |
| Restricted cash | 28 | 718 |
| Accounts receivable trade, net | 11,845 | 13,707 |
| Other receivables | 1,153 | 2,269 |
| Inventory | 6,161 | 9,702 |
| Other current assets | 2,771 | 8,141 |
| Current derivative financial instrument assets | 31,588 | 10,624 |
| Total current assets | 54,276 | 66,045 |
| Oil and natural gas properties under full cost method of accounting, net | 116,488 | 40,478 |
| Pipeline assets, net | 61,148 | 136,017 |
| Other property and equipment, net | 15,964 | 19,433 |
| Other assets, net | 9,303 | 2,727 |
| Long-term derivative financial instrument assets | 39,633 | 18,955 |
| Total assets | $ 296,812 | $ 283,655 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities | | |
| Accounts payable | $ 7,030 | $ 10,852 |
| Revenue payable | 5,898 | 5,895 |
| Accrued expenses | 8,210 | 11,417 |
| Current portion of notes payable | 10,500 | 310,015 |
| Current derivative financial instrument liabilities | 3,792 | 1,447 |
| Total current liabilities | 35,430 | 339,626 |
| Long-term derivative financial instrument liabilities | 6,681 | 8,569 |
| Notes payable | 209,721 | 19,295 |
| Asset retirement obligations | 7,150 | 6,552 |
| Total liabilities | 258,982 | 374,042 |
| Commitments and contingencies | | |
| Series A Cumulative Redeemable Preferred Stock, $0.01 par value; issued and outstanding 6,000 shares (liquidation value of $61,980) | 50,622 | |
| Stockholders equity | | |

| | | |
|---|---|---|
| Preferred stock of Predecessor, $0.001 par value; authorized shares 50,000,000; none issued and outstanding | | |
| Common stock of Predecessor, $0.001 par value; authorized shares 200,000,000; issued 32,160,121; outstanding 31,981,317 | | 33 |
| Preferred stock, $0.01 par value; authorized shares 5,000,000; 195,842 Series B Voting Preferred Stock issued and outstanding | 2 | |
| Common stock, $0.01 par value; authorized shares 40,000,000; issued and outstanding 8,238,982 | 82 | |
| Additional paid-in capital | 377,538 | 299,010 |
| Treasury stock of Predecessor at cost | | (7) |
| Accumulated deficit | (390,414) | (447,413) |
| Total stockholders deficit | (12,792) | (148,377) |
| Noncontrolling interests | | 57,990 |
| Total (deficit) equity | (12,792) | (90,387) |
| Total liabilities and equity | $ 296,812 | $ 283,655 |

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

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## POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF OPERATIONS

| | March 6, 2010 to December 31, 2010 | January 1, 2010 to March 5, 2010 | (Predecessor) Years Ended December 31, 2009 | 2008 |
|---|---|---|---|---|
| | ($ in thousands, except per share data) | | | |
| Revenue | | | | |
| Oil and gas sales | $ 69,277 | $ 18,659 | $ 79,893 | $ 162,499 |
| Gathering revenue | 4,771 | 1,076 | 7,760 | 8,704 |
| Pipeline revenue | 8,380 | 1,749 | 18,428 | 19,472 |
| Total revenues | 82,428 | 21,484 | 106,081 | 190,675 |
| Costs and expenses | | | | |
| Oil and gas production | 38,329 | 8,645 | 55,961 | 66,218 |
| Pipeline operating | 5,195 | 1,110 | 6,573 | 7,635 |
| General and administrative expenses | 20,705 | 5,735 | 41,723 | 28,269 |
| Depreciation, depletion and amortization | 18,683 | 4,164 | 47,802 | 70,445 |
| (Gain) loss on sale of assets | (13,495) | | 25 | (24) |
| Impairments | | | 268,630 | 298,861 |
| Recovery of misappropriated funds | (1,592) | | (3,412) | |
| Total costs and expenses | 67,825 | 19,654 | 417,302 | 471,404 |
| Operating income (loss) | 14,603 | 1,830 | (311,221) | (280,729) |
| Other income (expense) | | | | |
| Gain from derivative financial instruments | 47,870 | 25,246 | 48,122 | 66,145 |
| Gain on forgiveness of debt | 2,909 | | | |
| Other income (expense) | (24) | (4) | 108 | 305 |
| Interest expense | (20,169) | (5,340) | (29,573) | (25,609) |
| Interest income | 32 | 4 | 244 | 236 |
| Total other income (expense) | 30,618 | 19,906 | 18,901 | 41,077 |
| Income (loss) before income taxes and noncontrolling interests | 45,221 | 21,736 | (292,320) | (239,652) |
| Income tax benefit (expense) | | | | |
| Net income (loss) | 45,221 | 21,736 | (292,320) | (239,652) |
| Net (income) loss attributable to noncontrolling interests | | (9,958) | 147,398 | 72,268 |
| Net income (loss) attributable to controlling interests | 45,221 | 11,778 | (144,922) | (167,384) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Preferred stock dividends | | (1,980) | | | | | | |
| Accretion of redeemable preferred stock | | (327) | | | | | | |
| Net income (loss) available to common stockholders | $ | 42,914 | $ | 11,778 | $ | (144,922) | $ | (167,384) |
| Net income (loss) per share attributable to common stockholders | | | | | | | | |
| Basic | $ | 5.29 | $ | 0.37 | $ | (4.55) | $ | (6.20) |
| Diluted | $ | 4.62 | $ | 0.36 | $ | (4.55) | $ | (6.20) |
| Weighted average common and common equivalent shares outstanding | | | | | | | | |
| Basic | | 8,110 | | 32,137 | | 31,833 | | 27,011 |
| Diluted | | 9,295 | | 32,614 | | 31,833 | | 27,011 |

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

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | | | Predecessor | |
|---|---|---|---|---|
| | March 6, 2010 to December 31, 2010 | January 1, 2010 to March 5, 2010 | Years Ended December 31, 2009 | 2008 |
| | ($ in thousands) | | | |
| Cash flows from operating activities | | | | |
| Net income (loss) | $ 45,221 | $ 21,736 | $ (292,320) | $ (239,652) |
| Adjustments to reconcile net income (loss) to cash provided by operations | | | | |
| Depreciation, depletion and amortization | 18,683 | 4,164 | 47,802 | 70,445 |
| Impairments | | | 268,630 | 298,861 |
| Stock-based compensation | 1,635 | 808 | 1,279 | 2,425 |
| Amortization of deferred financing costs | 5,753 | 2,094 | 7,761 | 2,100 |
| Change in fair value of derivative financial instruments | (19,611) | (21,573) | 50,026 | (72,533) |
| Recovery of misappropriated funds, net of liabilities assumed | (487) | | (977) | |
| Loss (Gain) on disposal of property and equipment | (13,495) | | 25 | (24) |
| Gain on troubled debt restructuring | (2,909) | | | |
| Other non-cash changes to items affecting net loss | 138 | | 1,000 | |
| Change in assets and liabilities | | | | |
| Accounts receivable | 2,400 | (237) | 3,008 | (1,158) |
| Other receivables | (199) | 1,014 | 7,165 | (7,954) |
| Other current assets | (486) | 466 | 1,461 | 4,173 |
| Other assets | (3,224) | 2 | 193 | 318 |
| Accounts payable | (4,773) | (83) | (25,115) | 5,233 |
| Revenue payable | 160 | (157) | (2,526) | 584 |
| Accrued expenses | 735 | 983 | 7,142 | (1,187) |
| Other | 17 | | 65 | 269 |
| Net cash flows from operating activities | 29,558 | 9,217 | 74,619 | 61,900 |
| Cash flows from investing activities | | | | |
| Restricted cash | 691 | (1) | (159) | 677 |
| Acquisition of business PetroEdge | | | | (141,777) |
| Equipment, drilling, leasehold and pipeline | (25,858) | (2,282) | (8,426) | (141,553) |
| Proceeds from sale of oil and gas properties | 14,062 | | 8,898 | 16,100 |
| Net cash flows from investing activities | (11,105) | (2,283) | 313 | (266,553) |

| | | | | |
|---|---|---|---|---|
| Cash flows from financing activities | | | | |
| Proceeds from bank borrowings | 2,100 | 900 | 4,300 | 214,195 |
| Repayments of bank borrowings | (102,023) | (41) | (67,413) | (59,800) |
| Distributions to unit holders | | | | (24,413) |
| Debt and equity financing costs | (6,477) | | (4,720) | (3,018) |
| Repurchase of restricted stock | | | | (7) |
| Proceeds from issuance of preferred stock | 60,000 | | | |
| Proceeds from issuance of common stock | | | | 84,801 |
| Net cash flows from financing activities | (46,400) | 859 | (67,833) | 211,758 |
| Net increase (decrease) in cash | (27,947) | 7,793 | 7,099 | 7,105 |
| Cash and cash equivalents beginning of period | 28,677 | 20,884 | 13,785 | 6,680 |
| Cash and cash equivalents end of period | $ 730 | $ 28,677 | $ 20,884 | $ 13,785 |

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

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS (DEFICIT) EQUITY**
**FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 and 2008**

| | Preferred Shares | Preferred Stock Par Value | Common Shares Issued | Common Stock Par Value | Additional Paid-in Capital | Shares of Treasury Stock | Treasury Stock | Accumulated Deficit | Total Stockholders (Deficit) Equity | Non-Controlling Interests |
|---|---|---|---|---|---|---|---|---|---|---|
| | ($ in thousands, except share amounts) | | | | | | | | | |
| **ber 31,** | | | | | | | | | | |
| | | $ | 23,553,230 | $ 24 | $ 211,852 | | $ | $ (135,107) | $ 76,769 | $ 297,385 |
| tock | | | | | | | | | | |
| | | | 8,800,000 | 9 | 84,692 | | | | 84,701 | 486 |
| pensation | | | | | 1,939 | | | | 1,939 | |
| grants, net | | | | | | | | | | |
| | | | (138,587) | | | | | | | |
| k options | | | 10,000 | | 100 | | | | 100 | |
| ommon | | | | | | | | | | |
| | | | | | | 21,955 | (7) | | (7) | |
| interests | | | | | | | | | | (21,067 |
| | | | | | | | | (167,384) | (167,384) | (72,268 |
| **ber 31,** | | | | | | | | | | |
| | | | 32,224,643 | 33 | 298,583 | 21,955 | (7) | (302,491) | (3,882) | 204,536 |
| pensation | | | | | 427 | | | | 427 | 852 |
| grants, net | | | | | | | | | | |
| | | | (64,522) | | | | | | | |
| | | | | | | | | (144,922) | (144,922) | (147,398 |
| **ber 31,** | | | | | | | | | | |
| | | | 32,160,121 | 33 | 299,010 | 21,955 | (7) | (447,413) | (148,377) | 57,990 |
| pensation | | | | | 210 | | | | 210 | 598 |
| grants, net | | | | | | | | | | |
| | | | (1,687) | | | | | | | |
| | | | | | | | | 11,778 | 11,778 | 9,958 |
| **5, 2010** | | | 32,158,434 | $ 33 | $ 299,220 | 21,955 | $ (7) | $ (435,635) | $ (136,389) | $ 68,546 |
| **6, 2010** | | | | | | | | | | |
| ecessor | | | | | | | | | | |
| on | | | | | | | | | | |
| | | | 1,847,458 | 18 | 299,228 | | | (435,635) | (136,389) | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| ecessor | | | | | | | | |
| nterests | | | | | | | | |
| tion | | | 6,191,516 | 62 | 68,484 | | 68,546 | |
| npensation | | | | 2 | 1,633 | | 1,635 | |
| grants, net | | | | | | | | |
| | | | 200,008 | | | | | |
| es B | | | | | | | | |
| | 195,842 | 2 | | | | | 2 | |
| ants | | | | | 11,685 | | 11,685 | |
| preferred | | | | | | | | |
| nts | | | | | (1,185) | | (1,185) | |
| dividends | | | | | (1,980) | | (1,980) | |
| accretion | | | | | (327) | | (327) | |
| | | | | | | 45,221 | 45,221 | |
| **nber 31,** | | | | | | | | |
| | 195,842 | $ 2 | 8,238,982 | $ 82 | $ 377,538 | $ (390,414) | $ (12,792) | $ |

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

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

## Note 1 Business Organization

PostRock Energy Corporation ( PostRock ) is a Delaware corporation formed on July 1, 2009, for the purpose of effecting the recombination of Quest Resource Corporation ( QRCP ), Quest Energy Partners, L.P. ( QELP ) and Quest Midstream Partners, L.P. ( QMLP ). On July 2, 2009, PostRock, QRCP, QELP, QMLP and other parties thereto entered into a merger agreement pursuant to which QRCP, QELP and QMLP would recombine (the Recombination ). The Recombination was effected by forming a new publicly traded corporation, subsequently named PostRock, that, through a series of mergers and entity conversions, wholly owns all three entities. The Recombination was completed on March 5, 2010. Since QRCP was the parent company which consolidated both QELP and QMLP prior to the Recombination, the Recombination was a transaction between equity interest holders within a consolidated entity rather than a business combination. The transaction was therefore accounted for on a historical cost basis. Since PostRock did not own any assets prior to the consummation of the Recombination, the purpose of these consolidated financial statements is to present the historical consolidated financial position and results of operations, cash flows and changes in equity of the predecessor entities (collectively referred to as Predecessor ) prior to the Recombination and to present such information for PostRock subsequent to the Recombination. Unless the context requires otherwise, references to we, us, our or the Company are intended to mean and include the consolidated businesses and operati of our Predecessor for dates prior to March 6, 2010, and to the consolidated businesses and operations of PostRock and its subsidiaries for dates on or subsequent to March 6, 2010.

The Company is an independent oil company engaged in the acquisition, exploration, development, production and gathering of crude oil and natural gas. It manages its business in two segments, production and pipeline. Its production segment is focused in the Cherokee Basin, a 15-county region in southeastern Kansas and northeastern Oklahoma. It also has minor oil producing properties in Oklahoma and certain other minor gas producing properties in the Appalachian Basin. The Company s pipeline segment consists of a 1,120 mile interstate natural gas pipeline, which transports natural gas from northern Oklahoma and western Kansas to Wichita and Kansas City (the KPC Pipeline ). The Company acquired the KPC Pipeline in November 2007.

## Note 2 Summary of Significant Accounting Policies

*Principles of Consolidation* These consolidated financial statements include the Company s and its subsidiaries accounts. Subsidiaries in which the Company directly or indirectly owns more than 50% of the outstanding voting securities or those in which the Company has effective control over are generally accounted for under the consolidation method of accounting. Under this method, a subsidiaries balance sheet and results of operations are reflected within the Company s consolidated financial statements. The equity of the noncontrolling interests in the Company s majority-owned or effectively controlled subsidiaries are shown in the consolidated financial statements as noncontrolling interest . Noncontrolling interest adjusts the consolidated results of operations to reflect only the Company s share of the earnings or losses of the consolidated subsidiary. Upon dilution of control below 50% or the loss of effective control, the accounting method is adjusted to the equity or cost method of accounting, as appropriate, for subsequent periods. All significant intercompany accounts and transactions have been eliminated.

*Use of Estimates in the Preparation of Financial Statements* The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ( GAAP ) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company s most significant recurring estimates are based on remaining proved oil and gas reserves. Estimates of proved reserves are key components of the Company s depletion rate for oil and gas properties and its full cost ceiling test limitation. In addition,

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

estimates are used in computing fair value of impaired assets, taxes, asset retirement obligations, fair value of derivative contracts and other items. Actual results could differ from these estimates.

*Revenue Recognition* Revenue from the Company s oil and gas operations is derived from the sale of produced oil and natural gas. The Company uses the sales method of accounting for the recognition of oil and gas revenue. Because there is a ready market for oil and gas, the Company sells its oil and gas shortly after production at various pipeline receipt points at which time title and risk of loss transfers to the buyer. Revenue is recorded when title and risk of loss is transferred based on the Company s net revenue interests.

Gathering revenue is recognized at the time the gas is gathered or transported through the system and delivered to a third party. Transportation revenue from the Company s interstate pipeline operations is primarily from services pursuant to firm transportation agreements. These agreements provide for a demand charge based on the volume of contracted capacity and a commodity charge based on the volume of gas delivered, both at rates specified in the Company s Federal Energy Regulatory Commission ( FERC ) tariffs. The Company recognizes revenues from demand charges ratably over the contract period regardless of the volume of gas that is transported or stored. Revenues for commodity charges are recognized when gas is scheduled to be delivered at the agreed upon delivery point.

*Cash and Cash Equivalents* The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. Cash balances are maintained at several financial institutions that are insured by the Federal Deposit Insurance Corporation although such balances typically are in excess of the insured amount; however, no losses have been recognized as a result of this circumstance. Restricted Cash represents cash pledged to support reimbursement obligations under outstanding letters of credit.

*Accounts Receivable* The Company conducts the majority of its operations in Kansas and Oklahoma and operates exclusively in the oil and gas industry. Receivables are generally unsecured; however, the Company has not experienced any significant losses to date. Receivables are recorded at the estimate of amounts due based upon the terms of the related agreements. Management periodically assesses the accounts receivable and establishes an allowance for estimated uncollectible amounts. Accounts determined to be uncollectible are charged to operations in the period determined to be uncollectible. The allowance for doubtful accounts was approximately $0.3 million and $1.2 million as of December 31, 2010 and 2009, respectively.

*Other Current Assets* Other current assets consists of prepaid fees, prepaid insurance, deposits and certain short terms investments for which there are trading restrictions. The balance of such short term investments, carried at fair value, was $1.4 million and nil as of December 31, 2010 and 2009, respectively.

*Inventory* Inventory includes tubular goods and other lease and well equipment which the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market using the specific identification method.

*Oil and Natural Gas Properties* The Company uses the full cost method of accounting for oil and gas properties. Under the full cost method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of its oil and gas properties are capitalized.

Oil and gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved oil and gas reserves.

Estimation of proved oil and gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Holding all other factors constant, if proved oil and gas reserve quantities were revised upward or downward, earnings would increase or decrease, respectively. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of oil and

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

gas properties unless the deferral of gains or losses will result in an amortization rate materially different from the amortization rate calculated upon recognition of gains or losses.

Under the full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the ceiling limitation ). The Company performs a quarterly ceiling test to evaluate whether the net book value of its full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion, and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders (deficit) equity in the period of occurrence and typically results in lower depreciation, depletion, and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date. The risk that the Company will be required to write down the carrying value of its oil and gas properties increases when oil and gas prices are depressed, even if low prices are temporary. This is partially mitigated by recent changes in accounting rules requiring the use of a twelve-month average of market prices to determine the ceiling. In addition, a write-down may occur if estimates of proved reserves are substantially reduced or estimates of future development costs increase significantly.

*Unevaluated Properties* The costs directly associated with unevaluated oil and gas properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base once determination has been made or upon expiration of a lease. Geological and geophysical costs associated with a specific unevaluated property are transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. All items included in the Company s unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. Any impairments to unevaluated properties are transferred to the amortization base.

*Capitalized General and Administrative Expenses* Under the full cost method of accounting, a portion of general and administrative expenses that are directly attributable to acquisition, exploration, and development activities are capitalized to the full cost pool. The capitalized costs include salaries, related fringe benefits, cost of consulting services and other costs directly associated with those activities. The Company capitalized general and administrative costs of $0.8 million and $3.0 million related to its acquisition, exploration and development activities, for the period from March 6 to December 31, 2010 and for the year ended December 31, 2008, respectively. It did not capitalize any general and administrative expenses in 2009 due to the significant decrease in its acquisition and development activities.

*Capitalized Interest Costs* The Company capitalizes interest based on the cost of major development projects. For the year ended December 31, 2008, the Company capitalized $0.6 million of interest. No interest was capitalized in for the years ended December 31, 2010 and 2009.

*Other Property and Equipment* The cost of other property and equipment is depreciated over the estimated useful lives of the related assets. The cost of leasehold improvements is depreciated over the lesser of the length of the related leases or the estimated useful lives of the assets.

Upon disposition or retirement of property and equipment, other than oil and gas properties, the cost and related accumulated depreciation are removed from the accounts and the gain or loss thereon, if any, is recognized in the statement of operations in the period of sale or disposition.

*Impairment* Long-lived assets, such as property, equipment, and finite-lived intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

carrying amount of such assets may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of such assets to estimated undiscounted future cash flows expected to be generated by the assets. If the carrying amount of such assets exceeds their undiscounted estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of such assets exceeds the fair value of the assets.

*Other Assets* Other assets include deferred noncurrent portion of financing costs associated with bank credit facilities, escrowed funds from the sale of oil and gas properties and contract-related intangible assets. Deferred financing costs are amortized over the term of the credit facility into interest expense. The escrowed funds are restricted for 18 months to cover indemnities and title defects pursuant to the purchase agreement governing the sale. The contract-related intangible assets were obtained in connection with the KPC Pipeline acquisition; they are amortized over their estimated useful lives and are reviewed for impairment whenever impairment indicators are present.

*Asset Retirement Obligations* Asset retirement obligations associated with the retirement of a tangible long-lived asset are recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company s credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

The Company owns oil and gas properties that require expenditures to plug and abandon the wells when the oil and gas reserves in the wells are depleted. These expenditures are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). Asset retirement obligations are recorded as a liability at their estimated present value at the asset s inception, with the offsetting increase to property cost. Periodic accretion expense of the estimated liability is recorded in the consolidated statements of operations. The Company has recorded asset retirement obligations relative to the abandonment of its interstate pipeline assets because the Company believes it has a legal or constructive obligation relative to asset retirements of the interstate pipeline system. It has not recorded an asset retirement obligation relating to its gathering system because it does not have any legal or constructive obligations relative to asset retirements of the gathering system.

*Derivative Instruments* The Company utilizes derivative instruments in conjunction with marketing and trading activities to manage price risk attributable to its forecasted sales of oil and gas production.

The Company elects Normal Purchases Normal Sales ( NPNS ) accounting for derivative contracts that provide for the purchase or sale of a physical commodity that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Derivatives that are designated as NPNS are accounted for under the accrual method accounting.

For those derivatives that do not meet the requirements for NPNS designation nor qualify for hedge accounting, the Company believes that they are still effective as economic hedges of its commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Using this method, the contracts are carried at their fair value on the Company s consolidated balance sheets under the captions Derivative financial instrument assets and Derivative financial instrument liabilities. The Company recognizes all unrealized and realized gains and losses related to these contracts on its consolidated statements of operations under the caption Gain (loss) from derivative financial instruments, which is a component of other income (expense).

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The Company has exposure to credit risk to the extent a counterparty to a derivative instrument is unable to meet its settlement commitment. It actively monitors the creditworthiness of each counterparty and assesses the impact, if any, on its derivative positions. The Company does not apply hedge accounting to its derivative instruments. As a result, both realized and unrealized gains and losses on derivative instruments are recognized in the statement of operations as they occur.

*Legal* The Company is subject to legal proceedings, claims and liabilities which arise in the ordinary course of its business. It accrues for losses associated with legal claims when such losses are probable and can be reasonably estimated. These estimates are adjusted as additional information becomes available or circumstances change.

*Environmental Costs* Environmental expenditures are expensed or capitalized, as appropriate, depending on future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and costs can be reasonably estimated. The Company has no environmental costs accrued for the periods presented.

*Stock-Based Compensation* The Company grants various types of stock-based awards (including stock options and restricted stock) and accounts for stock-based compensation at fair value. The fair value of stock option awards is determined using a Black-Scholes pricing model. The fair value of restricted stock awards are valued using the market price of the Company s common stock on the grant date. Stock-based compensation expense is recognized over the requisite service period net of estimated forfeitures.

The Company accounts for stock-based compensation in accordance with Financial Accounting Standards Board ( FASB ) Accounting Standards Codification ( ASC ) 718 *Compensation Stock Compensation*, which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements based on their estimated grant-date fair value.

*Income Taxes* The Company records its income taxes using an asset and liability approach in accordance with the provisions of the FASB ASC 740 *Income Taxes*. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences (primarily intangible drilling costs and the net operating loss carry forward) between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under FASB ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2010 and 2009, a full valuation allowance was recorded against the Company s net deferred tax assets.

On January 1, 2007, the Company adopted the provisions of FASB ASC 740 regarding the criteria an individual tax position must meet in order to be recognized in the financial statements. FASB ASC 740 provides guidance on the measurement of the income tax benefit associated with uncertain tax positions, derecognition, classification, interest, penalties and financial statement disclosure. The Company regularly analyzes tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed under FASB ASC 740. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. The Company accrues interest and penalties related to uncertain tax positions as income tax expense.

*Net Income (Loss) per Common Share* Basic earnings (loss) per share is calculated by dividing net income (loss) available to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted earnings (loss) per share assumes the conversion of all potentially dilutive securities (stock options and restricted stock awards) and is calculated by dividing net income (loss)

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities under the treasury stock method.

*Concentrations of Market Risk* The Company s future results will be affected by the market price of oil and gas. The availability of a ready market for oil and gas will depend on numerous factors beyond the Company s control, including weather, production of oil and gas, imports, marketing, competitive fuels, proximity of oil and gas pipelines and other transportation facilities, any oversupply or undersupply of oil and gas, the regulatory environment, and other regional and political events, none of which can be predicted with certainty.

*Concentrations of Credit Risk* Financial instruments, which subject the Company to concentrations of credit risk, consist primarily of cash and accounts receivable. The Company places cash investments with highly qualified financial institutions. Risk with respect to receivables as of December 31, 2010 and 2009 arise substantially from the sales of oil and gas and transportation revenue from its pipeline system.

ONEOK Energy Marketing and Trading Company ( ONEOK ) accounted for 60%, 81% and 81% of oil and gas revenue for the years ended December 31, 2010, 2009 and 2008, respectively.

*Fair Value* Effective January 1, 2008, the Company adopted FASB ASC 820 *Fair Value Measurements and Disclosures* ( FASB ASC 820 ), for financial assets and liabilities measured on a recurring basis and subsequently adopted the full provisions of FASB ASC 820 effective January 1, 2009. Fair value is the exit price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

FASB ASC 820 also establishes a hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

*Level 1* Quoted prices available in active markets for identical assets or liabilities as of the reporting date.

*Level 2* Pricing inputs other than quoted prices in active markets included in Level 1 which are either directly or indirectly observable as of the reporting date. Level 2 consists primarily of non-exchange traded commodity derivatives.

*Level 3* Pricing inputs include significant inputs that are generally less observable from objective sources.

The Company classifies assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Certain derivatives are classified as Level 3 because observable market data is not available for all of the time periods for which the Company has derivative instruments. As observable market data becomes available for all of the time periods, these derivative positions will be reclassified as Level 2. The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of the Company s derivative instruments classified as Level 2 or Level 3. The Company prioritizes the use of the highest level inputs available in determining fair value.

The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Because of the long-term nature of certain assets and liabilities measured at fair value as well as differences in the availability of market prices and market liquidity over their terms, inputs for some assets and liabilities may fall into any one of the three levels in the fair value hierarchy. While FASB ASC 820 requires classification of these assets and liabilities in the lowest level in the hierarchy for which inputs are significant to the fair value measurement, a portion of that measurement may be determined using inputs from a higher level in the hierarchy.

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

***Recent Accounting Pronouncements***

In January 2010, the FASB released Accounting Standards Update ( ASU ) 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements.* The update requires reporting entities to provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy established under FASB ASC 820. The update also requires separate presentation (on a gross basis rather than as one net number) about purchases, sales, issuances, and settlements within the reconciliation of activity in Level 3 fair value measurements. The guidance is effective for any fiscal period beginning after December 15, 2009, except for the requirement to separately disclose purchases, sales, issuances, and settlements, which will be effective for any fiscal period beginning after December 15, 2010. The Company adopted the provisions of this update relating to disclosure on movement of assets among Levels 1 and 2 beginning with the quarter ended March 31, 2010. Other than additional disclosure required by the update, there was no material impact on its financial statements.

In February 2010, the FASB released ASU 2010-09, *Subsequent Events (Topic 855): Amendments to Certain Recognition and Disclosure Requirements* which removed some contradictions between the requirements of GAAP and the SEC s filing rules. As a result, public companies will no longer have to disclose the date of their financial statements in both issued and revised financial statements. The amendments became effective upon issuance of the update and the Company adopted the provisions of this update beginning with the quarter ended March 31, 2010, with no material impact on its financial statements.

**Note 3 Acquisitions and Divestitures**

***Acquisitions***

*PetroEdge* On July 11, 2008, QRCP completed the acquisition of privately held PetroEdge Resources (WV) LLC ( PetroEdge ) in an all cash purchase for approximately $142 million in cash including transaction costs, subject to certain adjustments for working capital and certain other activity between May 1, 2008, and the closing date. The assets acquired were approximately 78,000 net acres of oil and gas producing properties in the Appalachian Basin with estimated net proved reserves of 99.6 Bcfe as of May 1, 2008, and net production of approximately 3.3 million cubic feet equivalent per day ( Mmcfe/d ).

We accounted for this acquisition in accordance with FASB ASC 805. The purchase price was allocated to assets acquired and liabilities assumed based on estimated fair values of the respective assets and liabilities at the time of closing. The following table summarizes the allocation of the purchase price (in thousands):

| | |
|---|---|
| Current assets | $ 3,069 |
| Oil and gas properties | 142,618 |
| Gathering facilities | 1,820 |
| Current liabilities | (3,537) |
| Asset retirement obligations | (2,193) |
| Purchase price | $ 141,777 |

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

*Pro Forma Summary Data related to acquisitions (unaudited)*

The following unaudited pro forma information summarizes the results of operations for the year ended December 31, 2008, as if the PetroEdge acquisition had occurred on January 1, 2008 (in thousands):

| | 2008 |
|---|---|
| Pro forma revenue | $ 182,813 |
| Pro forma net loss | $ (246,175) |
| Pro forma net loss per share basic | $ (7.79) |
| Pro forma net loss per share diluted | $ (7.79) |

The pro forma information is presented for illustration purposes only, in accordance with the assumptions set forth below. The pro forma information does not reflect any cost savings or other synergies anticipated as a result of the acquisitions or any future acquisition-related expenses. The pro forma adjustments are based on estimates and assumptions. Management believes the estimates and assumptions are reasonable and that the significant effects of the transactions are properly reflected.

The pro forma information is a result of combining our income statement with the pre-acquisition results PetroEdge adjusted for 1) recording pro forma interest expense on debt incurred to acquire PetroEdge; 2) DD&A expense calculated based on the adjusted basis of the properties and intangibles acquired using the purchase method of accounting; and 3) any related income tax effects of these adjustments based on the applicable statutory tax rates.

***Divestitures***

*Appalachia Basin Asset Sale* On December 24, 2010, the Company entered into a Purchase and Sale Agreement (the Purchase Agreement ) with Magnum Hunter Resources Corporation ( MHR ) pursuant to which a subsidiary of MHR agreed to purchase from the Company certain oil and gas properties and leasehold mineral interests and related assets located in Wetzel and Lewis Counties, West Virginia (the Purchased Assets ). These assets were part of the assets previously purchased from PetroEdge and discussed above. The sale of these assets closed in two phases for aggregate consideration of $39.7 million. The Company closed the first phase for the assets located in the Wetzel County on December 30, 2010, for $28.0 million and closed the second phase for assets located in Lewis County on January 14, 2011, for $11.7 million. The purchase price on both closings was paid (i) 50% in cash in the total amount of $19.8 million, and (ii) 50% in approximately 3.2 million restricted shares of MHR common stock. The value of the Share Consideration was based on the volume weighted average price of MHR common stock on the NYSE Amex for the 10 consecutive trading days prior to the date on which the parties entered into the Purchase Agreement, or approximately $6.21 per share. The Purchase Agreement also contains provisions for a third closing if certain events and conditions are met before May 15, 2011. There can be no assurance that the third closing will occur.

Regulation S-X Rule 4-10 *Financial Accounting and Reporting for Oil and Gas Producing Activities Pursuant to the Federal Securities Laws and the Energy Policy and Conservation Act of 1975* specified that no gains or losses are recognized upon the sale or disposition of oil and gas properties unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. In general, a significant alteration occurs when the deferral of gains or losses will result in an amortization rate materially different from the amortization rate calculated upon recognition of gains or losses. The Company s evaluation demonstrated that a material difference in amortization rates would occur if no gain was recognized on the sale described above and therefore recorded a gain of $13.7 million, net of $0.7 million in selling costs, on the first phase sale. The corresponding reduction in the carrying amount of its oil and gas full cost pool related to the first phase of the sale was $13.6 million. The Company will

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

record a gain of $10.0 million, net of $0.1 million in selling costs, in January 2011 related to second phase of the sale with a corresponding reduction in the carrying amount of its oil and gas full cost pool of $1.5 million.

On February 13, 2009, the Company divested approximately 23,000 net undeveloped acres and one well in Lycoming County, Pennsylvania to a private party for approximately $8.7 million. On November 5, 2008, the Company divested 50% of its interest in approximately 4,500 net undeveloped acres in Wetzel County, West Virginia to a private party for $6.1 million. On October 30, 2008, the Company divested approximately 22,600 net undeveloped acres and one well in Somerset County, Pennsylvania to a private party for approximately $6.8 million. On November 26, 2008, the Company divested certain development and drilling rights covering approximately 28,700 net acres in Potter County, Pennsylvania to a private party for approximately $3.2 million. The proceeds from divestitures during 2009 and 2008 reduced the full cost pool.

**Note 4 Property**

Oil and gas properties, pipeline assets and other property and equipment were comprised of the following as of December 31, 2010 and 2009 (in thousands):

| | 2010 | Predecessor 2009 |
|---|---|---|
| Oil and gas properties under the full cost method of accounting | | |
| Properties being amortized(1) | $ 319,966 | $ 205,199 |
| Properties not being amortized | 188 | 596 |
| Total oil and gas properties, at cost | 320,154 | 205,795 |
| Less accumulated depletion, depreciation and amortization | (203,666) | (165,317) |
| Oil and gas properties, net | $ 116,488 | $ 40,478 |
| Pipeline assets, at cost(1) | $ 75,480 | $ 170,737 |
| Less accumulated depreciation | (14,332) | (34,720) |
| Pipeline assets, net | $ 61,148 | $ 136,017 |
| Other property and equipment at cost | $ 33,154 | $ 33,704 |
| Less accumulated depreciation | (17,190) | (14,271) |
| Other property and equipment, net | $ 15,964 | $ 19,433 |

(1) The increase in oil and gas properties and the decrease in pipeline assets from the prior year is primarily due to reclassifying the Company s operations and assets of its gathering system in the Cherokee Basin from its former natural gas pipelines segment to its production segment in the fourth quarter of 2010 as described below.

*Reclassification of gathering system* During the fourth quarter of 2010, the Company reclassified the operations and assets of its gathering system in the Cherokee Basin from its former natural gas pipelines segment to its production segment. The reclassification was prompted by, among other things, the expiration of the midstream services and gas dedication agreement between Bluestem Pipeline, LLC and QELP, the refinancing of the Company s debt facilities during the third quarter of 2010, the legal restructuring of the Company s subsidiaries and a change in management s approach to evaluating its business units. As a result of the reclassification, the carrying value of assets related to the Company s gathering system in the Cherokee Basin of $77.2 million was transferred to the full cost pool at the beginning of the fourth quarter of 2010. The depletion, depreciation and amortization amounts for all periods disclosed in the preceding paragraph reflect

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

the reclassification of the gathering system assets to the oil and gas full cost pool in the fourth quarter of 2010.

Depreciation on pipeline assets and other property and equipment is computed on the straight-line basis over the following estimated useful lives:

| | |
|---|---|
| Pipelines | 15 to 40 years |
| Buildings | 25 years |
| Machinery and equipment | 10 years |
| Software and computer equipment | 3 to 5 years |
| Furniture and fixtures | 10 years |
| Vehicles | 7 years |

For the periods from January 1 to March 5, 2010, and from March 6 to December 31, 2010, depletion, depreciation and amortization expense on oil and gas properties amounted to $2.9 million and $12.0 million, respectively; depreciation expense on pipeline assets amounted to $0.5 million and $2.5 million, respectively; and depreciation expense on other property and equipment amounted to $0.6 million and $3.4 million, respectively. For the years ended December 31, 2009 and 2008 depletion, depreciation and amortization expense (excluding impairment amounts discussed below) on oil and gas properties amounted to $35.5 million and $56.2 million, respectively; depreciation expense on pipeline assets amounted to $5.0 million and $5.7 million, respectively; and depreciation expense on other property and equipment amounted to $3.5 million and $3.8 million, respectively.

*Impairment of oil and gas properties* As of December 31, 2010, the Company s net book value of oil and gas properties was below the full cost ceiling. Accordingly, a provision for impairment was not required in the fourth quarter of 2010 and no impairment was recorded during the prior quarters of 2010. The Company recorded impairments of $102.9 million and $298.9 million for the years ended December 31, 2009 and 2008, respectively.

As discussed above, during the fourth quarter of 2010, the Company reclassified the operations and assets of its gathering system in the Cherokee Basin from its former natural gas pipelines segment to its production segment. The gathering system was subject to an impairment charge of $112.2 million during the fourth quarter of 2009. The impairment was due to a reduction in projected future gathering revenues associated with the Company s Cherokee Basin production partially the result of the capital expenditure limits contained in the Company s former credit facilities.

*Impairment of pipeline related assets* During the fourth quarter of 2009, the Company recorded an impairment of $52.6 million on its pipeline assets and $1.0 million on the related contract-intangibles. The impairment was triggered by the Company s inability to negotiate a new contract with one of its major customers, Missouri Gas and Electric ( MGE ). Its existing contract with MGE expired in October 2009, although prior to the expiration the Company believed that the contract could be extended or renegotiated with MGE or replaced by another customer.

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**Note 5 Other Assets**

Other assets were comprised of the following as of December 31, 2010 and 2010 and 2009 (in thousands)

| | 2010 | Predecessor 2009 |
|---|---|---|
| Intangible assets | $ 968 | $ 1,260 |
| Deferred financing costs | 4,010 | 252 |
| Escrowed funds | 4,200 | |
| Plugging and abandonment bond | | 1,000 |
| Other | 125 | 215 |
| Total other assets | $ 9,303 | $ 2,727 |

*Intangible Assets* Balances for the contract-related intangibles acquired in the KPC Pipeline acquisition were as follows as of December 31, 2010 and 2009 (in thousands):

| | 2010 | Predecessor 2009 |
|---|---|---|
| Gross carrying amount | $ 9,934 | $ 9,934 |
| Accumulated amortization | (7,931) | (7,635) |
| Impairment | (1,035) | (1,035) |
| Net carrying amount | $ 968 | $ 1,264 |

These intangibles are recorded in other assets and are being amortized over the term of the related contracts, which range from five to ten years. Projected amortization expense is expected to be $0.3 million a year for the next three years, $0.1 million in the fourth year and nil in the fifth year. Amortization expense related to those contracts for the periods from January 1 to March 5, 2010, and from March 6 to December 1, 2010, was $0.1 million and $0.2 million, respectively. Amortization expense related to those contracts was $3.3 million and $4.3 million for the years ended December 31, 2009 and 2008, respectively.

As discussed in Note 4, the Company recorded an impairment of its KPC pipeline during the fourth quarter of 2009 upon the loss of a contract with a major customer. The impairment analysis included the contract-related intangibles as part of the asset grouping for which the lowest level of independent cash flows could be identified apart from cash flows attributable to other assets and liabilities of the Company s pipeline segment. Upon determining the write-off required for the asset group, the Company allocated a pro-rata portion of the write-off to the contract related intangibles of $1.0 million. The write-off is reflected as a component of impairments in the consolidated statement of operations for the year ended December 31, 2009.

*Deferred Financing Costs* The unamortized deferred financing costs at December 31, 2010 and 2009 were $4.0 million and $7.0 million, respectively, and are being amortized over the life of the related credit facilities. The $4.0 million balance as of December 31, 2010, is reflected in other assets, net (noncurrent). Of the $7.0 million balance as of December 31, 2009, $6.3 million was reflected in other current assets while the remainder was reflected in other assets, net (noncurrent). As discussed in Note 10 Long Term Debt, the Company restructured its credit agreements during the third quarter of 2010. The unamortized balance of debt fees related to the former credit agreements were $1.8 million at the time of the restructuring. The Company evaluated the restructurings to determine whether there were substantial modifications to the remaining cash flows of the facilities or whether the borrowing capacity on any of the facilities had been reduced. Depending on circumstances, FASB ASC 470-50 *Debt Modifications and Extinguishments* requires complete or partial write-offs of unamortized debt issuance costs when the debt amendments substantially modify cash flows or when there is a reduction in borrowing capacity in connection with revolving lines of credit. As a result of the

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

restructuring, the Company wrote off the unamortized balance of $1.8 million related to its former credit agreements. The Company recorded similar write-offs for $3.5 million during 2009 as a result of various amendments to its credit facilities. The Company s expense related to amortizing or writing off deferred financing costs was $2.1 million and $5.7 million for the periods from January 1 to March 5, 2010, and from March 6 to December 1, 2010, respectively. The expense was $7.8 million and $2.1 million in 2009 and 2008, respectively. These costs are included in interest expense.

*Escrowed Funds* The Company had $4.2 million of escrowed funds as of December 31, 2010, related to the proceeds from the first phase of the sale of certain oil and gas properties to MHR (see Note 3). The escrowed funds are restricted for 18 months to cover indemnities and title defects related to the sale.

**Note 6 Asset Retirement Obligations**

Asset retirement obligations are included in other long-term liabilities on the Company s balance sheet. The following table describes the changes to the asset retirement liability for periods presented (in thousands):

| | | Predecessor | |
|---|---|---|---|
| | March 6 to December 31, 2010 | January 1 to March 5, 2010 | 2009 |
| Asset retirement obligations at beginning of year | $ 6,648 | $ 6,552 | $ 5,922 |
| Liabilities incurred | 41 | | 78 |
| Liabilities settled | (23) | (1) | (13) |
| Divestitures | (5) | | |
| Accretion | 489 | 97 | 565 |
| Asset retirement obligations at end of year | $ 7,150 | $ 6,648 | $ 6,552 |

**Note 7 Derivative Financial Instruments**

The Company is exposed to commodity price risk and management believes it prudent to periodically reduce exposure to cash-flow variability resulting from this volatility. Accordingly, the Company enters into certain derivative financial instruments in order to manage exposure to commodity price risk inherent in its oil and gas production. Specifically, the Company may utilize futures, swaps and options. Futures contracts and commodity swap agreements are used to fix the price of expected future oil and gas sales at major industry trading locations, such as Henry Hub, Louisiana for gas and Cushing, Oklahoma for oil. Basis swaps are used to fix or float the price differential between the price of gas at Henry Hub and various other market locations. Options are used to fix a floor and a ceiling price (collar) for expected future oil and gas sales. Derivative financial instruments are also used to manage commodity price risk inherent in customer pricing requirements and to fix margins on the future sale of natural gas.

Settlements of any exchange-traded contracts are guaranteed by the New York Mercantile Exchange (NYMEX) or the Intercontinental Exchange and are subject to nominal credit risk. Over-the-counter traded swaps, options and physical delivery contracts expose us to credit risk to the extent the counterparty is unable to satisfy its settlement commitment. The Company monitors the creditworthiness of each counterparty and assesses the impact, if any, on fair value. In addition, it routinely exercises its contractual right to net realized gains against realized losses when settling with our swap and option counterparties.

The Company accounts for its derivative financial instruments in accordance with FASB ASC 815 *Derivatives and Hedging* ( FASB ASC 815 ). FASB ASC 815 requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. FASB ASC 815 requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met or exemptions

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

for normal purchases and normal sales as permitted by FASB ASC 815 exist. The Company does not designate its derivative financial instruments as hedging instruments for financial accounting purposes and, as a result, it recognizes the change in the respective instruments fair value currently in earnings. In accordance with FASB ASC 815, the table below outlines the classification of derivative financial instruments on the consolidated balance sheet and their financial impact on the consolidated statements of operations as of and for the periods indicated (in thousands):

**Fair Value of Derivative Financial Instruments**

| | | December 31, | |
|---|---|---|---|
| **Derivative Financial Instruments** | **Balance Sheet location** | **2010** | **Predecessor 2009** |
| Commodity contracts | Current derivative financial instrument asset | $ 31,588 | $ 10,624 |
| Commodity contracts | Long-term derivative financial instrument asset | 39,633 | 18,955 |
| Commodity contracts | Current derivative financial instrument liability | (3,792) | (1,447) |
| Commodity contracts | Long-term derivative financial instrument liability | (6,681) | (8,569) |
| | | $ 60,748 | $ 19,563 |

Gains and losses associated with derivative financial instruments related to oil and gas production were as follows for the years ended December 31, 2010, 2009, and 2008 (in thousands):

| | | Predecessor | | |
|---|---|---|---|---|
| | **March 6 to December 31, 2010** | **January 1 to March 5, 2010** | **2009** | **2008** |
| Realized gain (loss)(1) | $ 28,259 | $ 3,673 | $ 98,148 | $ (6,388) |
| Unrealized gain (loss) | 19,611 | 21,573 | (50,026) | 72,533 |
| Total gain from derivative financial instruments | $ 47,870 | $ 25,246 | $ 48,122 | $ 66,145 |

(1) In 2009, includes $26 million received in June 2009 from exiting or amending certain above market natural gas derivative contracts.

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following tables summarize the estimated volumes, fixed prices and fair value attributable to oil and gas derivative contracts as of December 31, 2010. The Company does not have any outstanding derivative contracts beyond 2013.

| | Year Ending December 31, 2011 | 2012 | 2013 | Total |
|---|---|---|---|---|
| | ($ in thousands, except volumes and per unit data) | | | |
| **Natural Gas Swaps** | | | | |
| Contract volumes (Mmbtu) | 13,550,302 | 11,000,004 | 9,000,003 | 33,550,309 |
| Weighted-average fixed price per Mmbtu | $ 6.80 | $ 7.13 | $ 7.28 | $ 7.04 |
| Fair value, net | $ 31,588 | $ 22,728 | $ 16,905 | $ 71,221 |
| **Natural Gas Basis Swaps** | | | | |
| Contract volumes (Mmbtu): | 8,549,998 | 9,000,000 | 9,000,003 | 26,550,001 |
| Weighted-average fixed price per Mmbtu | $ (0.67) | $ (0.70) | $ (0.71) | $ (0.69) |
| Fair value, net | $ (3,417) | $ (3,405) | $ (3,031) | $ (9,853) |
| **Crude Oil Swaps** | | | | |
| Contract volumes (Bbl) | 48,000 | 42,000 | | 90,000 |
| Weighted-average fixed price per Bbl | $ 85.90 | $ 87.90 | $ | $ 86.83 |
| Fair value, net | $ (375) | $ (245) | $ | $ (620) |
| **Total fair value, net** | **$ 27,796** | **$ 19,078** | **$ 13,874** | **$ 60,748** |

The following tables summarize the estimated volumes, fixed prices and fair value attributable to natural gas derivative contracts as of December 31, 2009:

| | Year Ending December 31, 2010 | 2011 | 2012 | Thereafter | Total |
|---|---|---|---|---|---|
| | ($ in thousands, except volumes and per unit data) | | | | |
| **Natural Gas Swaps** | | | | | |
| Contract volumes (Mmbtu) | 16,129,060 | 13,550,302 | 11,000,004 | 9,000,003 | 49,679,369 |
| Weighted-average fixed price per Mmbtu | $ 6.26 | $ 6.80 | $ 7.13 | $ 7.28 | $ 6.78 |
| Fair value, net | $ 10,424 | $ 7,530 | $ 6,662 | $ 4,763 | $ 29,379 |
| **Natural Gas Basis Swaps** | | | | | |
| Contract volumes (Mmbtu): | 3,630,000 | 8,549,998 | 9,000,000 | 9,000,003 | 30,180,001 |
| Weighted-average fixed price per Mmbtu | $ (0.63) | $ (0.67) | $ (0.70) | $ (0.71) | $ (0.69) |
| Fair value, net | $ (1,402) | $ (2,973) | $ (2,879) | $ (2,717) | $ (9,971) |
| **Crude Oil Swaps** | | | | | |
| Contract volumes (Bbl) | 30,000 | | | | 30,000 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Weighted-average fixed price per Bbl | $ | 87.50 | $ | | $ | | $ | | $ | 87.50 |
| Fair value, net | $ | 155 | $ | | $ | | $ | | $ | 155 |
| **Total fair value, net** | **$** | **9,177** | **$** | **4,557** | **$** | **3,783** | **$** | **2,046** | **$** | **19,563** |

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

## Note 8 Financial Instruments

The Company s financial instruments include commodity derivatives, debt, cash, receivables, payables and redeemable preferred stock. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of those instruments.

ASU 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements* requires reporting entities to provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy established under FASB ASC 820. There were no movements between Levels 1 and 2 during 2010 and 2009.

*Assets and Liabilities Measured at Fair Value on a Recurring Basis* The following table sets forth, by level within the fair value hierarchy, our assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2010 and 2009 (in thousands):

| **PostRock**<br>**At December 31, 2010** | **Level 1** | **Level 2** | **Level 3** | **Total Net Fair Value** |
|---|---|---|---|---|
| Short term investments other current assets | $ | $ 1,354 | $ | $ 1,354 |
| Derivative financial instruments assets | $ | $ 71,221 | $ | $ 71,221 |
| Derivative financial instruments liabilities | $ | $ (620) | $ (9,853) | $ (10,473) |
| Total | $ | $ 71,955 | $ (9,853) | $ 62,102 |

| **Predecessor**<br>**At December 31, 2009** | **Level 1** | **Level 2** | **Level 3** | **Total Net Fair Value** |
|---|---|---|---|---|
| Derivative financial instruments assets | $ | $ 18,033 | $ 11,546 | $ 29,579 |
| Derivative financial instruments liabilities | $ | $ | $ (10,016) | $ (10,016) |
| Total | $ | $ 18,033 | $ 1,530 | $ 19,563 |

Risk management assets and liabilities in the table above represent the current fair value of all open derivative positions, excluding those derivatives designated as NPNS. The Company classifies all of these derivative instruments as Derivative financial instrument assets or Derivative financial instrument liabilities in its consolidated balance sheets.

In order to determine the fair value amounts presented above, the Company utilizes various factors, including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and parental guarantees), but also the impact of nonperformance risk on the Company s liabilities. The Company utilizes observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating its assets from counterparties.

The Company s commodity derivative instruments consist of variable to fixed price commodity swaps, and basis swaps. In addition to the valuation factors described above, the Company estimates the fair values of these instruments based on published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates.

The Company s short term investments as of December 31, 2010, consists of common stock of MHR received as proceeds from the sale of certain Appalachia oil and gas assets, discussed previously. The fair value of these securities is based on the published market price of the common stock adjusted for a six month restriction on the Company s ability to trade the securities.

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following table sets forth a reconciliation of changes in the fair value of risk management assets and liabilities classified as Level 3 in the fair value hierarchy for the periods presented (in thousands):

| | March 6, 2010, December 31, 2010 | Predecessor January 1, 2010 to March 5, 2010 | Predecessor 2009 |
|---|---|---|---|
| Balance at beginning of period | $ 5,455 | $ 1,530 | $ 60,947 |
| Realized and unrealized gains included in earnings | 12,586 | 7,254 | 29,202 |
| Purchases, sales, issuances, and settlements | (7,595) | (3,329) | (88,619) |
| Transfers into and out of Level 3(1) | (20,299) | | |
| Balance at end of period | $ (9,853) | $ 5,455 | $ 1,530 |

(1) The availability of market based information starting in July 2010 has allowed the Company to reclassify a portion of its swap contracts from Level 3 to Level 2.

*Additional Fair Value Disclosures* The Company has 6,000 outstanding shares of Series A Cumulative Redeemable Preferred Stock (see Note 12 Redeemable Preferred Stock). The fair value and the carrying value of these securities as of December 31, 2010, were $68.5 million and $50.6 million, respectively. The fair value was determined by discounting the cash flows over the remaining life of the securities utilizing a LIBOR interest rate and a risk premium of approximately 6.9% which was based on companies with similar liquidity ratios to PostRock.

The Company s long term debt consists entirely of floating-rate facilities. The carrying amount of floating-rate debt approximates fair value because the interest rates paid on such debt are generally set for periods of six months or shorter.

**Note 9 Income Taxes**

The Company has not recorded any provision or benefit for income taxes for the years ended December 31, 2010, 2009 and 2008.

A reconciliation of federal income taxes at the statutory federal rates to our actual provision for income taxes for the periods from January 1 to March 5, 2010, and March 6 to December 31, 2010, and for the years ended December 31, 2010, 2009 and 2008 are as follows (in thousands):

| | March 6 to | Predecessor January 1 to |
|---|---|---|

| | December 31, 2010 | March 5, 2010 | 2009 | 2008 |
|---|---|---|---|---|
| Income tax expense (benefit) at statutory rate | $ 15,828 | $ 4,122 | $ (50,723) | $ (58,584) |
| State income tax expense (benefit), net of federal | (651) | 289 | (3,131) | (3,789) |
| Effect of the Recombination | (22,170) | | | |
| Other | (3,673) | 318 | 2,548 | 300 |
| IRC Section 382 limitation | 71,377 | 3,628 | | |
| Change in valuation allowance | (60,711) | (8,357) | 51,306 | 62,073 |
| Total tax expense (benefit) | $ | $ | $ | $ |

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred assets will not be realized based on the weight of all available evidence. Based on the negative evidence that existed as of each reporting period, the Company recorded a full valuation allowance against its net deferred tax asset as of December 31, 2010, 2009, and 2008.

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Deferred tax assets and liabilities as of December 31, 2010 and 2009 were as follows (in thousands):

| | 2010 | Predecessor 2009 |
|---|---|---|
| Current deferred income tax assets | | |
| Unrealized loss for commodity derivative recorded for book, not for tax | $ 1,414 | $ |
| Accrued liabilities | 1,416 | |
| Allowance for bad debts | 96 | |
| Total current deferred income tax assets | 2,926 | |
| Noncurrent deferred income tax assets | | |
| Unrealized loss for commodity derivative recorded for book, not for tax | 2,490 | |
| Partnership basis differences | | 49,889 |
| Property and equipment | 91,942 | 19,284 |
| Asset retirement obligations | 1,966 | |
| Net operating loss carryforwards | 12,126 | 89,523 |
| Other carryforwards | 38 | 34 |
| Other | 1,909 | 979 |
| Total noncurrent deferred income tax assets | 110,471 | 159,709 |
| Total deferred income tax assets | 113,397 | 159,709 |
| Current deferred income tax liabilities | | |
| Unrealized gain for commodity derivative recorded for book, not for tax | (11,774) | |
| Total current deferred income tax liabilities | (11,774) | |
| Noncurrent deferred income tax liabilities | | |
| Unrealized gain for commodity derivative recorded for book, not for tax | (14,773) | |
| Other | (1,084) | |
| Total noncurrent deferred income tax liabilities | (15,857) | |
| Total deferred income tax liabilities | (27,631) | |
| Net deferred income tax assets | 85,766 | 159,709 |
| Valuation allowance | (85,766) | (159,709) |
| Total deferred tax asset (liability) | $ | $ |

The Company has net operating loss ( NOL ) carryforwards that are available to reduce future U.S. taxable income. If not utilized, such carryforwards will expire from 2021 through 2030.

The Company s ability to utilize NOL carryforwards to reduce future federal taxable income and federal income tax of the Company is subject to various limitations under Internal Revenue Code ( IRC ) Section 382. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock of PostRock during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of PostRock. The Company experienced ownership changes within the meaning of IRC Section 382 on November 14, 2005,

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

March 5, 2010, and September 21, 2010. The Company has NOL carryforwards of approximately $247 million at December 31, 2010 that are available to reduce future U.S. taxable income in certain circumstances. At December 31, 2010, $234 million of federal NOL carryforwards are subject to the IRC Section 382 limitation and it is anticipated that $214 million of these federal NOL carryforwards will expire unused due to the IRC Section 382 limitation. As a result, only $33 million of federal NOL carryforwards have been recorded as a deferred tax asset. The limitation does not result in a current federal tax liability for the period ending December 31, 2010.

On March 5, 2010, the Company completed the Recombination of QRCP, QELP and QMLP. Prior to the Recombination, the Company recorded a deferred tax asset related to basis differences in QELP and QMLP in the above table as partnership basis differences. As a result of the Recombination, the Company recorded a gross deferred tax asset of $210.3 million related to basis differences in fixed assets, a gross deferred tax asset related to derivative liabilities of $12.8 million, a gross deferred tax liability related to derivative assets of $53.9 million and other gross deferred tax assets totaling $11.9 million. There is a net unrealized built in loss (NUBIL) at the March 5, 2010, ownership change of $37.8 million, which will limit the Company s ability to claim tax depreciation, depletion and amortization for a 60-month period following the ownership change.

The ownership change on September 21, 2010, is a result of the Company issuing 6,000 shares of new Series A Cumulative Redeemable Preferred Stock, 190,476 shares of Series B Voting Preferred Stock and warrants to purchase 19,047,619 shares of common stock of the Company to White Deer Energy Partners L.P. in exchange for $60 million of cash. A NUBIL of $179.3 million existed at this date which will limit the Company s ability to claim tax depreciation, depletion and amortization for a 60-month period following the ownership change.

On December 30, 2010, certain assets located in Wetzel County, West Virginia, were sold to MHR (see Note 3), resulting in a recognized built-in loss of $12.3 million. The Company also had recognized built-in losses of $20.4 million due to depreciation and depletion expense limitations as a result of the ownership changes described above. It is anticipated that $31.7 million of these recognized built-in losses will expire unused.

FASB ASC 740-10 provides guidance for recognizing and measuring uncertain tax positions. Based upon the provision of FASB ASC 740-10, the Company did not record any amounts for uncertain tax benefits upon adoption of the standard and have no amounts recorded for uncertain tax benefits as of December 31, 2010. Accordingly, there has been no change in unrecognized tax benefits during the year. The Company files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. Tax years ended December 31, 2009, 2008 and 2007 remain open for examination by the relevant taxing authorities. In addition, the Company s tax returns for the tax years ended December 31, 2001, through December 31, 2006, can be examined and adjustments made to the amount of net operating losses flowing from those years into an open tax year. However, no assessment of income tax may generally be made for those years on which the statute has closed. The Company s policy is to recognize interest and penalties, if any, related to unrecognized tax benefits as income tax expense.

## POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

### Note 10 Long-Term Debt

The following is a summary of long-term debt as of the dates indicated (in thousands):

| | December 31, 2010 | (Predecessor) December 31, 2009 |
|---|---|---|
| New Credit Agreements | | |
| Borrowing Base Facility | $ 187,000 | $ |
| Secured Pipeline Loan | 13,500 | |
| QER Loan | 19,721 | |
| Former Credit Agreements | | |
| Quest Cherokee Loan | | 145,000 |
| Second Lien Loan | | 29,821 |
| Midstream Loan | | 118,728 |
| PESC Loan | | 35,658 |
| Notes payable to banks and finance companies | | 103 |
| Total debt | 220,221 | 329,310 |
| Less current maturities included in current liabilities | 10,500 | 310,015 |
| Total long-term debt | $ 209,721 | $ 19,295 |

***Former Credit Agreements***

On September 21, 2010, the Company completed a restructuring of its credit agreements. Prior to the restructuring, the Company had the following four credit agreements (the Former Credit Agreements ):

(i) A term loan with an outstanding principal balance of approximately $125 million and no available capacity, secured by the Company s assets owned by Quest Cherokee, LLC (the Quest Cherokee Loan );

(ii) A second lien senior term loan with an outstanding principal balance of approximately $30.2 million, secured by a second lien on the Company s assets owned by Quest Cherokee, LLC (the Second Lien Loan );

(iii) A credit agreement with an outstanding principal balance of approximately $118.7 million secured by the Company s assets owned by PostRock Midstream LLC and Bluestem Pipeline, LLC, which included the Bluestem gas gathering system and the KPC Pipeline (the Midstream Loan ); and

(iv) A credit agreement with an outstanding principal balance of approximately $43.8 million, secured by the Company s Appalachian assets owned indirectly by PostRock Energy Services Corporation (the PESC Loan ).

The terms of the Company s previous credit facilities and activity prior to the restructuring are described in Item 8. Financial Statement and Supplementary Data in the Company s Annual Report on Form 10-K for the year ended December 31, 2009, and in Part I, Item 1. in the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010.

***New Credit Agreements***

Concurrent with the debt restructuring and investment from White Deer (see Note 12), the Company repaid $58.9 million of debt. As a result of the restructuring, the Company now has the following credit agreements (the New Credit Agreements ):

(i) A $350 million secured borrowing base revolving credit facility with an initial borrowing base of $225 million and outstanding borrowings of $187.0 million as of December 31, 2010, secured by, among

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

other things, a first lien on the Company s Cherokee Basin exploration and production assets, certain producing Appalachian production assets and the Cherokee Basin gas gathering system and a second lien on the Company s interstate natural gas transportation pipeline (the Borrowing Base Facility );

(ii) A term loan with an outstanding principal balance of $13.5 million as of December 31, 2010, secured by, among other things, a first lien on the Company s interstate natural gas transportation pipeline and a second lien on the Company s Cherokee Basin exploration and production assets, certain producing Appalachian production assets and the Cherokee Basin gas gathering system (the Secured Pipeline Loan ); and

(iii) A term loan with a carrying amount of $19.7 million and outstanding principal balance of $22.6 million as of December 31, 2010, secured by the Company s assets owned by Quest Eastern Resource LLC ( QER ), which include certain producing and non-producing Appalachian properties and the Appalachian gas gathering system, and a pledge of the equity of QER (the QER Loan ).

***Borrowing Base Facility***

The Borrowing Base Facility with PostRock Energy Services Corporation ( PESC ) and PostRock MidContinent Production, LLC (formerly known as Bluestem Pipeline, LLC and the successor by merger to Quest Cherokee, LLC) ( MidContinent ) as borrowers, Royal Bank of Canada ( RBC ) as administrative and collateral agent, and the lenders party thereto is a secured borrowing base facility with an initial borrowing base of $225 million and is guaranteed by PostRock and certain of its subsidiaries.

Under the terms of the Borrowing Base Facility, MidContinent and PESC prepaid the outstanding indebtedness under the Quest Cherokee Loan in an amount equal to approximately $19.2 million. In consideration therefor, the lenders completely restructured the credit agreements relating to the Quest Cherokee Loan and the Second Lien Loan with the Borrowing Base Facility, partially restructured the Midstream Loan, and secured the Borrowing Base Facility with the same assets that secured the Quest Cherokee Credit Agreement and the Second Lien Loan Agreement (including the assets of MidContinent, which include all of the oil and gas exploration assets located in the Cherokee Basin and all of the oil and gas exploration assets located in the Appalachian basin that are not owned by QER) in addition to the Bluestem gathering pipeline system (which had formerly partially secured the Midstream Loan).

As of December 31, 2010, based on outstanding borrowings of $187.0 million and $1.5 million in letters of credit, the remaining availability under this facility was $36.5 million.

Material terms of the Borrowing Base Facility include the following:

*Covenants* The Borrowing Base Facility contains affirmative and negative covenants that are customary for transactions of this type, including financial covenants that prohibit PESC, MidContinent and any of their subsidiaries (with certain exceptions) from:

permitting the Company s current ratio (ratio of consolidated current assets (as defined in the agreement) to consolidated current liabilities (as defined in the agreement)) at any fiscal quarter-end to be less than or equal to 1.0 to 1.0;

permitting the Company s interest coverage ratio (ratio of adjusted consolidated EBITDA to consolidated interest charges) at any fiscal quarter-end to be less than or equal to 3.0 to 1.0 measured on a trailing four quarter basis; and

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

permitting the Company s leverage ratio (ratio of cash adjusted consolidated funded debt to adjusted consolidated EBITDA for the four fiscal quarters ending on the applicable fiscal quarter-end) (1) commencing with the quarter ending September 30, 2010, and ending on the quarter ending March 31, 2011, to be greater than or equal to 4.5 to 1.0, (2) commencing with the quarter ending June 30, 2011, and ending on the quarter ending March 31, 2012, to be greater than or equal to 4.0 to 1.0, and (3) commencing with the quarter ending June 30, 2012, and continuing until the maturity date to be greater than or equal to 3.5 to 1.0.

The Company was in compliance with all its covenants under the Borrowing Base Facility as of December 31, 2010.

*Interest Rate* LIBOR plus 3.50% to 4.00% or, at the borrowers option, Base Rate plus 2.50% to 3.00%, in each case depending on utilization. The interest rate on the outstanding borrowings at December 31, 2010, was 4.05%.

*Maturity Date June 30, 2013.*

*Capital Expenditures* The borrowers are obligated to make minimum capital expenditures in the cumulative aggregate amount of (1) $5.0 million for the six-month period ending December 31, 2010, (2) $10.0 million for the nine-month period ending March 31, 2011, (3) $17.5 million for the 12-month period ending June 30, 2011, and (4) $25.0 million for the 15-month period ending September 30, 2011. If the borrowers have not expended the required amounts by December 31, 2010, the borrowers are entitled to an additional quarter to expend that amount. In the event the borrowers have not expended the minimum aggregate capital expenditure amount required to be expended by March 31, 2011, June 30, 2011, or September 30, 2011, the borrowing base will be reduced by an amount equal to the shortfall.

*Borrowing Base Redetermination* The first borrowing base redetermination with respect to the indebtedness under the Borrowing Base Facility will be effective on July 31, 2011, and based on the Company s March 31, 2011, oil and gas reserves. After July 31, 2011, the borrowing base redeterminations by the lenders will be effective every April 30th and October 31st until maturity taking into account the value of MidContinent s proved reserves. In addition, the borrowers, during each period between scheduled redeterminations of the borrowing base, and, the required lenders, after the redetermination effective April 30, 2012, have the right to initiate a redetermination of the borrowing base between each scheduled redetermination, provided that no more than two such redeterminations may occur in a 12-month period. In addition, upon a material disposition of assets and a material acquisition of oil and gas properties, and in certain other limited circumstances, the borrowing base will or may be redetermined. If the borrowing base is reduced in connection with a redetermination, the borrowers can elect to either repay the entire deficiency within 30 days, repay the deficiency in six equal monthly installments, or contribute additional properties to increase the value of the collateral to support the prior borrowing base.

*Payments* Principal is required to be repaid on the maturity date. The borrowers are required to make a mandatory prepayment of principal upon the occurrence of any of the following events: (a) a material disposition of assets; (b) a sale of the Appalachian assets owned by MidContinent; (c) a change of control occurring after September 21, 2010; and (d) the existence of a borrowing base deficiency. Interest payments are due (i) at the end of each LIBOR interest period but in no event less frequently than quarterly in the case of LIBOR loans or (ii) quarterly in the case of Base Rate loans.

*Security Interest* The Borrowing Base Facility is secured by (i) a first lien on all of PostRock s assets except for the Appalachian properties owned by QER, the equity of QER, three lateral gas pipelines owned by Quest Transmission Company, LLC, the KPC Pipeline and the other assets of KPC and (ii) a second lien on the KPC Pipeline and the other assets of KPC.

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*Events of Default* Events of default are customary for transactions of this type and include, without limitation, non-payment of principal when due, non-payment of interest, fees and other amounts within three business days after the due date, failure to perform or observe covenants and agreements (subject to a 30-day cure period in certain cases), representations and warranties not being correct in any material respect when made, certain acts of bankruptcy or insolvency, cross defaults to other material indebtedness, non-appealable judgment in a material amount is entered against a borrower or its affiliate, ERISA violations, invalidity of loan documents, dissolution, collateral impairment, borrowing base deficiencies, and change of control.

***Secured Pipeline Loan***

The Secured Pipeline Loan with PESC and PostRock KPC Pipeline, LLC ( KPC ) as borrowers, RBC as administrative and collateral agent, and the lenders party thereto is a $15 million term loan secured by a first lien on the KPC Pipeline and the other assets of KPC, and by a second lien on the assets on which the lenders under the Borrowing Base Facility have a first lien.

Under the terms of the Secured Pipeline Loan, PESC and KPC prepaid approximately $14.7 million of the outstanding indebtedness under the Midstream Loan in exchange for the assignment by the lenders under the Midstream Loan of approximately $89.0 million of the indebtedness owing under the Midstream Loan to the lenders under the Borrowing Base Facility. The remaining $15.0 million of such indebtedness was retained under the Secured Pipeline Loan.

Other material terms of the Secured Pipeline Loan include the following:

*Covenants* The Secured Pipeline Loan contains affirmative and negative covenants that are customary for credit agreements of this type. The financial covenants in the Secured Pipeline Loan are substantially the same as the financial covenants in the Borrowing Base Facility.

The Company was in compliance with all its covenants under the Secured Pipeline Loan as of December 31, 2010.

*Interest Rate* LIBOR plus 3.75% or, at the borrowers option, Base Rate plus 2.75%. The interest rate on December 31, 2010, was 4.01%.

*Maturity Date* February 28, 2012.

*Payments* Principal payments in the amount of $0.5 million are due monthly for the first six months beginning October 21, 2010, and $1.0 million monthly thereafter, as well as monthly interest payments. Prepayments are required to be made in the following amounts: (a) net available cash from the sale of the KPC Pipeline or the equity of KPC and (b) total outstanding amounts upon a change of control.

*Events of Default* Events of default under the Secured Pipeline Loan are customary for transactions of this type and include, without limitation, non-payment of principal when due, non-payment of interest, fees and other amounts within three business days after the due date, failure to perform or observe covenants and agreements (subject to a 30-day cure period in certain cases), representations and warranties not being correct in any material respect when made, certain acts of bankruptcy or insolvency, cross defaults to other material indebtedness, non-appealable judgment in a material amount is entered against a borrower or its affiliate, ERISA violations, invalidity of loan documents, dissolution, collateral impairment, and change of control.

***QER Loan***

As part of the closing of our amended and restated credit facilities, PESC, QER and RBC entered into an assumption agreement whereby QER assumed all of PESC s rights and obligations as borrower under the PESC Loan. In addition, QER, as borrower, entered into the third amended and restated credit agreement with RBC in the amount of approximately $43.8 million. In connection therewith, RBC, the lender under the PESC

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Loan released PESC from any liability or obligation to repay amounts owing under the PESC Loan and all of the guarantors thereunder from their respective guarantees of the indebtedness owing under the PESC Loan and (except for QER) from their respective mortgages and security agreements. RBC also released the liens on all the collateral owned by PESC, other than the Appalachian assets owned by QER and the equity of QER; and agreed to reconvey the overriding royalty interests to their respective grantors (or their designees) at such time as the Appalachian assets or equity of QER are sold or all outstanding obligations under the credit agreement have been paid in full or otherwise deemed to have been satisfied. Accordingly, under the QER Loan, RBC has recourse only to QER, its assets and the equity of QER.

Other material terms of the QER Loan, as amended by the First Amendment to the QER Loan dated February 21, 2011, include the following:

*Covenants* The QER Loan contains non-financial affirmative and negative covenants that are customary for credit agreements of this type. There are no financial covenants contained in the QER Loan.

*Interest Rate* LIBOR plus 4.00% or, at the borrowers option, Base Rate plus 3.00%. The weighted average interest rate on December 31, 2010, was 4.28%.

*Maturity Date* June 30, 2013.

*Payments* No interim principal payments are scheduled under the QER Loan. Prior to May 16, 2011, no interest payments are due. Subsequent to May 16, 2011, interest payments on LIBOR loans are due on the last day of each LIBOR interest period, in no event less than quarterly, and interest payments on Base Rate Loans are due at the end of each quarter, beginning June 30, 2011. Mandatory prepayment of the net cash proceeds upon a disposition of the Appalachian assets owned by QER is required. The principal plus accrued interest is due at maturity.

*Security Interest* The QER Loan is secured by a first priority lien on the assets of QER and a pledge by PESC of QER s equity.

*Events of Default* Events of default are customary for transactions of this type and include, without limitation, non-payment of principal when due, non-payment of interest, fees and other amounts within three business days after the due date, failure to perform or observe covenants and agreements (subject to a 30-day cure period in certain cases), representations and warranties not being correct in any material respect when made, certain acts of bankruptcy or insolvency, non-appealable judgment in a material amount is entered against a borrower or its affiliate, ERISA violations, invalidity of loan documents, dissolution, collateral impairment, and change of control.

In connection with the QER Loan, the Company entered into an asset sale agreement with RBC that allows the Company to sell QER or its assets and, in the event the proceeds are not adequate to repay the QER Loan in full, the Company has agreed to pay a portion of such shortfall in cash, stock or a combination thereof.

As discussed in Note 3, the Company sold certain Appalachia Basin oil and gas properties to MHR in December 2010 and January 2011. The Company received total consideration of $28.0 million on the first closing in December 2010, consisting of $14.0 million in cash and 2.3 million shares of MHR common stock. Of the cash amount, $4.2 million was placed in escrow pursuant to the terms of the Purchase Agreement to cover indemnities and title defects. The Company received total consideration of $11.7 million for the second closing in January 2011, consisting of

$5.8 million in cash and 0.9 million shares of MHR common stock. Of the cash amount, $1.7 million was placed in escrow. Included in the $39.7 million aggregate purchase price was approximately $36.7 million representing the purchase price of assets owned by QER pledged as collateral under the QER Loan. Approximately $12.1 million of the net cash consideration and the share consideration received by QER pursuant to the purchase agreement (totaling 3.0 million shares) were paid to RBC in repayment of the QER Loan and as consideration for the release of RBC s liens encumbering the assets sold, which resulted in payments to RBC of $21.2 million in December 2010 and $9.3 million in January 2011 from the first and second phases of the asset sale.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

*Troubled debt restructuring* The interest rate margin under the QER Loan of 3%-4% is lower than the margin under the previous PESC Loan, which was 10%. Due to a reduction in the interest rate coupled by the Company s recent financial difficulties, the QER Loan restructuring met the criteria under FASB ASC 470-60 Debt *Troubled Debt Restructurings by Debtors* ( FASB ASC 470-60 ) to be classified as a troubled debt restructuring. In accordance with accounting guidance, the Company evaluated whether the sum of future cash flows under the QER Loan would be less than the amount payable under the original loan (PESC Loan), which would require a gain to be recognized on the debt restructuring. At the end of the third quarter of 2010, the cash flows were indeterminate as they depend on the yet to be determined proceeds from the sale of QER s assets. Since such proceeds could potentially be sufficient to repay the QER Loan in full, the Company determined that it was not necessary to recognize a gain on the debt restructuring during the third quarter of 2010. As required by FASB ASC 470-60, the Company also expensed $0.8 million in fees incurred to restructure the debt during the third quarter of 2010, which is reflected in interest expense in the consolidated statements of operations.

The Company evaluated the restructuring of its former credit facilities that resulted in the Borrowing Base Facility and Secured Pipeline Loan and determined that they were not troubled debt restructurings.

As a result of entering into the Purchase Agreement for the sale of the Company s Appalachia Basin assets which specified the purchase price of the assets sold, the Company was able to estimate the maximum possible future cash proceeds paid to RBC in satisfaction of the QER Loan. As this amount was less than the principal balance of the QER Loan, the Company reduced the carrying amount of the QER Loan by $2.9 million while recording a corresponding gain on troubled debt restructuring during the fourth quarter of 2010. The gain, which increased basic earnings per share by $0.36 for the period from March 6, 2010, to December 31, 2010, is reflected as a component of other income (expense) in the consolidated statement of operations. The gain from troubled debt restructuring reduced the carrying amount of the QER Loan from $22.6 million to $19.7 million as of December 31, 2010.

***Debt fees***

Prior to the successful restructuring of the Company s Former Credit Agreements, the unamortized balance of debt fees related to those agreements was $1.8 million. The Company wrote off the unamortized balance of $1.8 million in accordance with the provisions of FASB ASC 470-50 *Debt Modifications and Extinguishments*.

The Company incurred a total of $6.5 million in fees related to its New Credit Facilities and the White Deer investment of which $4.2 million related to the Borrowing Base Facility and $0.3 million related to the Secured Pipeline Loan and were capitalized, $0.8 million related to the QER Loan and were expensed, and the remaining $1.2 million related to the White Deer investment and were recorded as a reduction to additional paid-in capital. The write-off of unamortized debt fees and the fees related to the QER Loan have been recognized as a component of interest expense in the consolidated statements of operations.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**Note 11 Noncontrolling Interests**

| | January 1, 2010 to March 5, 2010(1) | 2009 |
|---|---|---|
| QELP | | |
| Beginning of period | $ 15,350 | $ 58,666 |
| Net income (loss) attributable to non-controlling interest | 10,365 | (43,553) |
| Stock compensation expense related to QELP unit-based awards | 167 | 237 |
| End of period | $ 25,882 | $ 15,350 |
| QMLP | | |
| Beginning of period | $ 42,640 | $ 145,870 |
| Net income (loss) attributable to non-controlling interest | (407) | (103,845) |
| Stock compensation expense related to QMLP unit-based awards | 431 | 615 |
| End of period | $ 42,664 | $ 42,640 |
| Total non-controlling interest at end of period | $ 68,546 | $ 57,990 |

(1) As a result of the Recombination on March 6, 2010, noncontrolling interests in QELP and QMLP were dissolved.

***QELP***

During November 2007, QELP completed its initial public offering of 9,100,000 common units (representing a 42.1% limited partner interest) for net proceeds of $151.3 million. QELP was formed by the Predecessor to own, operate, acquire and develop its oil and gas production operations in the Cherokee Basin. All proceeds from the sale of the common units were recorded as noncontrolling interest on the consolidated balance sheets. The noncontrolling interest was dissolved on March 6, 2010, as a result of the Recombination.

***QMLP***

During 2006, the Predecessor formed QMLP to own, operate, acquire and develop midstream assets by transferring pipeline assets and certain associated liabilities to QMLP as a capital contribution. At the same time, QMLP issued 4,864,866 common units to private investors for net proceeds of $84.2 million. All proceeds from the sale of the common units were recorded as noncontrolling interest on the consolidated balance sheet. Prior to the Recombination, QMLP owned and operated the KPC Pipeline and the Bluestem gas gathering system in the Cherokee Basin. The noncontrolling interest was dissolved on March 6, 2010, as a result of the Recombination.

**Note 12 Redeemable Preferred Stock and Warrants**

On September 21, 2010, the Company issued to White Deer 6,000 shares of the Company s Series A Cumulative Redeemable Preferred Stock (the Series A Preferred Stock ), 190,476.19 shares of its Series B Voting Preferred Stock (the Series B Preferred Stock ) and warrants to purchase 19,047,619 shares of the Company s common stock. The preferred stock and warrants were issued in exchange for $60 million.

The Series A Preferred Stock is entitled to a cumulative dividend of 12% per year on its liquidation preference, compounded quarterly. The liquidation preference was $60 million on the closing date of the equity investment and will increase by the amount of dividends paid in kind. The Company is not required to pay cash dividends until July 1, 2013. Any dividends prior to that time not paid in cash will accrue

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

as additional liquidation preference. Subsequent to July 13, 2013, dividends are required to be paid in cash, subject to the legal availability of funds for the declaration and payment thereof, and any payment default after that date will increase the accrual of the additional liquidation preference during the default period from a rate of 12% to 14%. The Company is required to redeem the Series A Preferred Stock on March 21, 2018 at 100% of the liquidation preference. From and after one year from the issuance date until such mandatory redemption date, the Company will have the option to redeem all or a specified minimum portion of the Series A Preferred Stock at 110% of the liquidation preference. The holders of the Series A Preferred Stock have the right to require the Company to purchase their shares on the occurrence of specified change in control events at 110% of the liquidation preference. In the case of specified defaults by the Company, including the failure to pay dividends for any quarterly period after July 1, 2013, and until the defaults are cured, the holders of the Series A Preferred Stock have the right to appoint two additional directors to the Board of Directors. The Series A Preferred Stock do not vote generally with the common stock, but have specified approval rights with respect to, among other things, changes to the Company s certificate of incorporation that affect the Series A Preferred Stock, cash dividends on the common stock or other junior stock, redemptions or repurchases of common stock or other capital stock, increases in the size of the Board of Directors, changes to specified debt agreements and changes to the Company s business.

The warrants issued at the closing of the investment are exercisable for a total of 19,047,619 shares of common stock at an exercise price of $3.15 per share which represents an approximate 5% premium to the closing price of the common stock on September 1, 2010, the day before the transaction was publicly announced. Prior to July 1, 2013, if dividends on the Series A Preferred Stock are not paid in cash on a dividend payment date, the Company will issue additional warrants exercisable for a number of shares of common stock equal to the amount of dividends that are not paid on that dividend payment date divided by the closing price of the common stock on the trading date immediately preceding the dividend payment date. The exercise price of the warrants will be such closing price. The warrants, including any additional warrants, are exercisable for 90 months following the applicable issuance date. Each warrant is coupled, and may only be transferred as a unit, with a number of one one-hundredths of a share, or a fractional share, of Series B Preferred Stock equal to the number of shares of common stock purchasable upon exercise of the warrant. The warrants and the Series B Preferred Stock may not be transferred separately. If and when the warrant is exercised, the holder of the warrant will be required to deliver to the Company, as part of the payment of the exercise price, a number of fractional shares of Series B Preferred Stock equal to the number of shares of common stock purchased upon such exercise. The holders of the warrants have the right to pay the exercise price in cash, by electing a cashless exercise (whereby the holder will receive the excess of the market price of the common stock over the exercise price in shares of common stock valued at the market price) or by tendering shares of Series A Preferred Stock with a liquidation preference equal to the exercise price. If the market price of the common stock exceeds 300% of the exercise price for a specified period of time and other conditions are satisfied, the Company may require the holders of the warrants to exercise warrants to purchase up to 50% of shares covered thereby, but in the aggregate not less than 750,000 shares or more than 50% of the trading volume of the common stock over the preceding 20 trading days.

The holders of Series B Preferred Stock are entitled to vote in the election of directors and on all other matters submitted to a vote of the holders of common stock of the Company, with the holders of Series B Preferred Stock and the holders of common stock voting together as a single class. Each fractional share of Series B Preferred Stock has one vote. The voting rights of each share of Series B Preferred Stock may not be exercised by any person other than the holder of the warrant that is part of the unit with such share or fractional share and will expire on the expiration date of such warrant. The Series B Preferred Stock has no dividend rights and a nominal liquidation preference. Until December 31, 2011, the holders of the Series B Preferred Stock and their affiliates are limited to 45% of the votes applicable to all outstanding voting stock, which limit includes any common stock held by them. After December 31, 2011, the limit only restricts the

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

voting of the Series B Preferred Stock, and the holders and their affiliates may vote any shares of common stock held by them without regard to that limit.

The Series A Preferred Stock has been recorded outside of permanent equity and liabilities, in the Company s consolidated balance sheet because the settlement provisions of the warrants allow White Deer to net exercise the warrants by requiring the Company to repay the Series A Preferred Stock at the liquidation preference to offset the strike price of the warrants that would otherwise be due from White Deer in cash. Absent this provision, the Series A Preferred Stock would have met the definition of mandatorily redeemable preferred stock under FASB ASC 480 *Distinguishing Liabilities from Equity* ( FASB ASC 480 ) which would have required recognition as a liability. This provision allows the Series A Preferred Stock to effectively be convertible to common stock at the election of White Deer. In the event that White Deer exercises the warrants without net-exercising the Series A Preferred Stock back to the Company as payment for the strike price of the warrants, the Company will be required to reclassify a proportionate amount of Series A Preferred Stock from temporary equity to liabilities as that portion of the Series A Preferred Stock is no longer convertible to common stock.

The White Deer investment was recognized on the Company s consolidated balance sheet based on the relative fair values of the Series A Preferred Stock, Series B Preferred Stock and the warrants allocated to the $60 million of gross proceeds. The warrants were recognized at an allocated value of $10.8 million on the date of issuance and recorded as additional paid in capital on the consolidated balance sheet. The preferred stock was recognized at an allocated value of $49.2 million and recorded in temporary equity related to the Series A Preferred Stock and approximately $2,000 was recorded in equity related to the par value of the Series B Preferred Stock. As the Series A Preferred Stock is recorded at a discount, it will be accreted to its full liquidation value over the 71/2 year term under the interest method in accordance with FASB ASC 480. Accretion for the year ended December 31, 2010, was $0.3 million. Offering fees of $1.2 million were recorded as a reduction of additional paid in capital.

The Company used a Monte Carlo stock option pricing simulation to value the warrants. The warrants are classified as Level 3 within the fair value hierarchy established by FASB ASC 820 because observable market data is not available. The assumptions used in the model for the warrant valuation included the exercise price of $3.15 per share and inputs relating to stock price drift and daily volatility. The Series A Preferred Stock also contains a put option whereby White Deer can put the stock to the Company at 110% of the liquidation preference upon a change in control. Under FASB ASC 815, Derivatives and Hedging, ( FASB ASC 815 ) it was determined that the put option is both indexed to the Company s own stock and classified in stockholder s equity as the underlying Series A Preferred Stock is classified as temporary equity. Accordingly, the put option is scoped out of FASB ASC 815 and does not require separate accounting as a bifurcated derivative. The Series A Preferred Stock was valued as a discount bond using the net present value method and considered to be a Level 3 valuation. Contractual cash flows were discounted using the continuous compounding method based on LIBOR swap rates and a risk premium commensurate with the Company s credit standing.

On December 31, 2010, the Company elected to not to pay cash dividends of $2.0 million accrued for the period from September 21 to December 31, 2010. Accordingly the liquidation preference of the Series A Preferred Stock increased by the same amount, and the Company issued additional warrants to purchase 536,586 shares of PostRock common stock at a strike price of $3.69 and 5,366 additional shares of Series B Preferred Stock. The Company recorded the increase in liquidation preference and the issuance of additional warrants by allocating their relative fair values to the $2.0 million amount of accrued dividends. The allocation resulted in an increase to the Company s temporary equity of $1.1 million related to the Series A Preferred Stock and an increase to additional paid in capital of $0.9 related to the additional warrants issued.

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The following table describes the changes in temporary equity currently comprised of the Series A Preferred Stock (in thousands except share amounts):

| | Series A Preferred Stock | | Number of Series A Preferred Shares |
|---|---|---|---|
| Balance on September 21, 2010 | $ | | |
| Issuance of Series A Preferred Stock | | 49,188 | 6,000 |
| Dividends paid in kind | | 1,107 | |
| Accretion | | 327 | |
| Balance on December 31, 2010 | $ | 50,622 | 6,000 |

As of December 31, 2010, the Series A Preferred Stock had a liquidation preference of $62.0 million and there were outstanding warrants to purchase a total of 19,584,205 shares of common stock at a weighted average exercise price of $3.16.

**Note 13 Stockholders Equity**

Restricted share and stock option awards of QRCP prior to the Recombination were made under the 2005 Omnibus Stock Award Plan (as amended). The granting of future stock awards and options to employees subsequent to the Recombination is governed by PostRock s 2010 Long-Term Incentive Plan (the LTIP ) of which 850,000 shares were initially authorized for future stock and option awards. Immediately prior to the Recombination, there were 1,155,327 restricted shares of QRCP, 945,593 phantom units of QELP and 732,784 restricted units of QMLP that were unvested. In the Recombination, 118,816 restricted shares of QRCP, 7,500 phantom units of QELP and 67,838 restricted units of QMLP were subject to immediate vesting immediately prior to the closing and, at closing, these awards converted to 36,416 shares of PostRock common stock. PostRock s predecessor and the predecessor s consolidated subsidiaries recognized $0.4 million of compensation expense related to the accelerated vesting discussed above. All remaining unvested awards were converted to 595,923 PostRock restricted share awards.

A summary of changes in the non-vested restricted shares for PostRock and its Predecessor for the periods presented is below:

| | Number of Non-Vested Restricted Shares | | Weighted Average Grant-Date Fair Value |
|---|---|---|---|
| **Predecessor** | | | |
| Non-vested restricted shares at December 31, 2007 | 1,081,875 | $ | 8.69 |

| | | | |
|---|---|---|---|
| Granted(a) | 405,362 | | 7.50 |
| Vested | (470,912) | | 8.28 |
| Forfeited | (533,949) | | 8.75 |
| Non-vested restricted shares at December 31, 2008 | 482,376 | | 8.01 |
| Granted(b) | 1,108,696 | | 0.38 |
| Vested | (274,609) | | 4.77 |
| Forfeited | (175,266) | | 7.93 |
| Non-vested restricted shares at December 31, 2009 | 1,141,197 | | 1.39 |
| Granted(c) | 52,174 | | 0.65 |
| Vested | (156,346) | | 7.72 |
| Forfeited | (514) | | 6.40 |
| Non-vested restricted shares at March 5, 2010 | 1,036,511 | $ | 0.39 |

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

| | Number of Non-Vested Restricted Share | Weighted Average Grant-Date Fair Value |
|---|---|---|
| **PostRock** | | |
| Non-vested restricted shares at March 6, 2010 | | $ |
| Converted upon Recombination(d) | 595,923 | 4.67 |
| Granted(e) | 114,836 | 5.86 |
| Vested | (191,544) | 4.40 |
| Forfeited | (143,857) | 5.56 |
| Non-vested restricted shares at December 31, 2010 | 375,358 | $ 4.83 |

(a) Includes 140,000 stock options converted to 70,000 restricted shares during the year.

(b) Consists of restricted shares granted to employees of QRCP, QELP and QMLP in December 2009. For those employees with greater than 18 months service, 20% of the shares vest immediately and 20% each year for four years. For those employees with less than 18 months service, 25% of the shares vest each year for four years.

(c) Shares granted vest 25% each year for four years.

(d) 1,036,511 restricted shares of QRCP, 938,093 phantom units of QELP and 664,946 restricted units of QMLP that were unvested at Recombination converted to 595,923 PostRock restricted share awards upon effectiveness of the Recombination.

(e) Consists of 60,800 restricted shares granted to non-employee directors that vested immediately; the remainder consists primarily of restricted shares to employees that vest 25% each year for four years.

As of December 31, 2010, total unrecognized stock-based compensation expense related to non-vested restricted shares was $1.0 million, which is expected to be recognized over a weighted average period of approximately 1.50 years while 225,364 shares were available under the LTIP for future stock awards and options.

*Stock Options* The LTIP also provides for the granting of options to purchase shares of PostRock s common stock. The Company has in the past has granted stock options to employees and non-employees. Option grants under the LTIP expire 5-10 years following the date of grant.

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

A summary of changes in stock options outstanding for PostRock and its predecessor is presented below:

| | Stock Options | Weighted Average Exercise Price per Share |
|---|---|---|
| **Predecessor** | | |
| Options outstanding at December 31, 2007 | 250,000 | $ 10.00 |
| Granted | 300,000 | 0.63 |
| Exercised | (10,000) | 10.05 |
| Converted | (140,000) | 10.03 |
| Options outstanding at December 31, 2008 | 400,000 | 2.98 |
| Granted | 300,000 | 0.62 |
| Exercised | | |
| Forfeited | (30,000) | 10.00 |
| Options outstanding at December 31, 2009 | 670,000 | 1.61 |
| Granted | | |
| Exercised | | |
| Forfeited | | |
| Options outstanding at March 5, 2010 | 670,000 | $ 1.61 |

| | Stock Options | Weighted Average Exercise Price per Share |
|---|---|---|
| **PostRock** | | |
| Options outstanding at March 6, 2010 | | $ |
| Converted upon Recombination (a) | 38,525 | 27.94 |
| Granted | 549,800 | 3.55 |
| Exercised | | |
| Forfeited | (21,275) | 30.96 |
| Options outstanding at December 31, 2010 | 567,050 | 4.17 |
| Options exercisable at December 31, 2010 | 127,250 | $ 4.34 |

(a) 670,000 stock options to purchase QRCP common stock were converted to stock options to purchase PostRock common stock upon effectiveness of the Recombination.

During 2010, PostRock granted 110,000 stock options to its non-employee directors that vested immediately and 439,800 stock options to employees that vest ratably over a three year period. The weighted average grant date fair value of stock options granted during 2010 was $2.28 per option. All the stock options granted during 2010 were subsequent to the Recombination and thus were for the purchase of PostRock common stock. The weighted average grant date fair value of stock options granted in 2009 and 2008, which were for the purchase of QRCP common stock, were $0.45 and $0.54 per share, respectively.

The weighted average remaining term of options outstanding and options exercisable at December 31, 2010 was 5.21 and 6.03 years, respectively. Options outstanding and options exercisable at December 31, 2010 had an aggregate intrinsic value of approximately $120,000 and $50,000 respectively.

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The Company determines the fair value of stock option awards using the Black-Scholes option pricing model. The expected life of the option is estimated based upon historical exercise behavior. The expected forfeiture rate was estimated based upon historical forfeiture experience. The volatility assumption was estimated based upon expectations of volatility over the life of the option as measured by historical and implied volatility. The risk-free interest rate was based on the U.S. Treasury rate for a term commensurate with the expected life of the option. The dividend yield was based upon a 12-month average dividend yield. The Company used the following weighted-average assumptions to estimate the fair value of stock options granted during the years ending December 31, 2010, 2009 and 2008.

| | | Predecessor | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| Expected option life years | 5-6 | 10 | 10 |
| Volatility | 75.2 - 84.1% | 101.2% | 69.8% |
| Risk-free interest rate | 1.8 - 2.0% | 4.93% | 5.42% |
| Dividend yield | | | |
| Fair value per share | $2.24 - $2.43 | $0.45 | $0.41 - $0.61 |

As of December 31, 2010, there was $1.0 million of total unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted average period of 1.47 years.

During 2008, the Predecessor converted 140,000 stock options held by certain directors into 70,000 shares of unvested restricted stock. As a result, additional compensation expense of $0.1 million was recognized for the year ended December 31, 2008.

Total share-based compensation covering stock awards and options for PostRock, its predecessor and the predecessor s consolidated subsidiaries is included in general and administrative expense on the consolidated statement of operations and presented below (in thousands):

| | Total Share Based Compensation Expense |
|---|---|
| **Predecessor** | |
| Year Ended December 31, 2008 | $ 2,425 |
| Year Ended December 31, 2009 | 1,279 |
| January 1, 2010, to March 5, 2010 | 808 |
| **PostRock** | |
| March 6, 2010, to December 31, 2010 | $ 1,635 |

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

*Earnings (Loss) per Share* A reconciliation of the numerator and denominator used in the basic and diluted per share calculations for the periods presented is as follows (in thousands, except share data):

| | | | (Predecessor) | |
|---|---|---|---|---|
| | March 6, 2010 to December 31, 2010 | January 1, 2010 to March 5, 2010 | 2009 | 2008 |
| Net income (loss) attributable to common stockholders | $ 42,914 | $ 11,778 | $ (144,922) | $ (167,384) |
| **Denominator** | | | | |
| Common shares | 8,110,348 | 32,016,327 | 31,833,222 | 27,010,690 |
| Weighted average number of unvested share-based awards participating(1) | | 121,121 | | |
| Denominator for basic earnings per share | 8,110,348 | 32,137,448 | 31,833,222 | 27,010,690 |
| **Effect of potentially dilutive securities** | | | | |
| Unvested share-based awards non-participating | 81,815 | 450,751 | | |
| Warrants | 1,102,798 | | | |
| Stock options | 123 | 26,154 | | |
| Denominator for diluted earnings per share | 9,295,084 | 32,614,353 | 31,833,222 | 27,010,690 |
| Basic earnings per share | $ 5.29 | $ 0.37 | $ (4.55) | $ (6.20) |
| Diluted earnings per share | $ 4.62 | $ 0.36 | $ (4.55) | $ (6.20) |
| **Securities excluded from earnings per share calculation** | | | | |
| Unvested share-based awards participating(1)(2) | | | 1,141,197 | 482,376 |
| Antidilutive stock options | 567,050 | 570,000 | 670,000 | 400,000 |

(1) FASB ASC 260 *Earnings Per Share* requires participating securities to be included in the allocation of earnings when calculating basic earnings per share, or EPS, under the two-class method. During periods of losses, these securities are not included in the basic EPS share computation. For the period from March 6 to December 31, 2010, there were no unvested participating share-based awards.

(2) Restricted stock awards were excluded for the years ended December 31, 2009 and 2008, because the Predecessor reported a net loss for those periods.

**Note 14 Commitments and Contingencies**

*Litigation* The Company is subject, from time to time, to certain legal proceedings and claims in the ordinary course of conducting its business. It records a liability related to its legal proceedings and claims when it has determined that it is probable that it will be obligated to pay and the related amount can be reasonably estimated. Except for those legal proceedings listed below, it believes there are no pending legal proceedings in which it is currently involved which, if adversely determined, could have a material adverse effect on its financial position, results of operations or cash flow. The Company intends to vigorously defend

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

against the claims described below. In some cases, the Company is unable to predict the outcome of these proceedings or reasonably estimate a range of possible loss that may result.

**Federal Class Action Securities Litigation**

***Michael Friedman, individually and on behalf of all others similarly situated v. Quest Energy Partners LP, Quest Energy GP LLC, Quest Resource Corporation, Jerry Cash, and David E. Grose, Case No. 08-cv-936-M, U.S. District Court for the Western District of Oklahoma, filed September 5, 2008***

***James Jents, individually and on behalf of all others similarly situated v. Quest Resource Corporation, Jerry Cash, David E. Grose, and John Garrison, Case No. 08-cv-968-M, U.S. District Court for the Western District of Oklahoma, filed September 12, 2008***

***J. Braxton Kyzer and Bapui Rao, individually and on behalf of all others similarly situated v. Quest Energy Partners LP, Quest Energy GP LLC, Quest Resource Corporation and David E. Grose , Case No. 08-cv-1066-M, U.S. District Court for the Western District of Oklahoma, filed October 6, 2008***

***Paul Rosen, individually and on behalf of all others similarly situated v. Quest Energy Partners LP, Quest Energy GP LLC, Quest Resource Corporation, Jerry Cash, and David E. Grose, Case No. 08-cv-978-M, U.S. District Court for the Western District of Oklahoma, filed September 17, 2008***

Four class action complaints were filed in the United States District Court for the Western District of Oklahoma naming QRCP, QELP and Quest Energy GP, LLC, the general partner of the predecessor of QELP ( QEGP ), and certain of their then current and former officers and directors as defendants. The complaints were filed by certain stockholders on behalf of themselves and other stockholders who purchased QRCP common stock between May 2, 2005 and August 25, 2008 and QELP common units between November 7, 2007 and August 25, 2008. The complaints assert claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as amended (the Exchange Act ), and Rule 10b-5 promulgated thereunder, and Sections 11 and 15 of the Securities Act of 1933. The complaints allege that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material facts concerning certain unauthorized transfers of funds from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaints also allege that, as a result of these actions, QRCP s stock price and the unit price of QELP were artificially inflated during the class period. On December 29, 2008, the Court consolidated these complaints. On July 9, 2010, a stipulation of settlement was filed in the consolidated federal action. On August 13, 2010, the Court entered an order preliminarily approving the settlement. On November 29, 2010, the Court approved the settlement and issued its Order and Final Judgment dismissing with prejudice all the federal individual and class securities actions as well as the federal derivative actions described herein. The settlement, however, did not become effective until the consolidated state court derivative cases were dismissed. Those derivative cases were dismissed on January 26, 2011, and the settlement became final as of that date. We contributed $1.0 million to the settlement of the lawsuits and agreed to pay approximately $0.4 million representing a portion of associated defense costs of certain individual defendants. These amounts have been substantially paid as of December 31, 2010.

**Federal Individual Securities Litigation**

***Bristol Capital Advisors v. Quest Resource Corporation, Inc., Jerry Cash, David E. Grose, and John Garrison, Case No. CIV-09-932, U.S. District Court for the Western District of Oklahoma, filed August 24, 2009***

On August 24, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma naming QRCP and certain then current and former officers and directors as defendants. The complaint was filed by an individual stockholder of QRCP. The complaint asserts claims under Sections 10(b) and 20(a) of the Exchange Act. The complaint alleges that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material information concerning unauthorized transfers from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer,

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Mr. Jerry D. Cash. The complaint also alleges that QRCP issued false and misleading statements and or/concealed material information concerning a misappropriation by its former chief financial officer, Mr. David E. Grose, of $1 million in company funds and receipt of unauthorized kickbacks of approximately $850,000 from a company vendor. The complaint also alleges that, as a result of these actions, QRCP s stock price was artificially inflated when the plaintiff purchased their shares of QRCP common stock. On November 29, 2010, the action was dismissed with prejudice as part of the settlement referred to above.

***J. Steven Emerson, Emerson Partners, J. Steven Emerson Roth IRA, J. Steven Emerson IRA RO II, and Emerson Family Foundation v. Quest Resource Corporation, Inc., Quest Energy Partners L.P., Jerry Cash, David E. Grose, and John Garrison, Case No. 5:09-cv-1226-M, U.S. District Court for the Western District of Oklahoma, filed November 3, 2009***

On November 3, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma naming QRCP, QELP, and certain then current and former officers and directors as defendants. The complaint was filed by individual shareholders of QRCP stock and individual purchasers of QELP common units. The complaint asserts claims under Sections 10(b) and 20(a) of the Exchange Act. The complaint alleges that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material information concerning unauthorized transfers from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaint also alleges that QRCP and QELP issued false and misleading statements and/or concealed material information concerning a misappropriation by its former chief financial officer, Mr. David E. Grose, of $1 million in company funds and receipt of unauthorized kickbacks of approximately $850,000 from a company vendor. The complaint also alleges that, as a result of these actions, the price of QRCP stock and QELP common units were artificially inflated when the plaintiffs purchased QRCP stock and QELP common units. The plaintiffs seek $10 million in damages. On November 29, 2010, the action was dismissed with prejudice as part of the settlement referred to above.

**Federal Derivative Cases**

***James Stephens, derivatively on behalf of nominal defendant Quest Resource Corporation v. William H. Damon III, Jerry Cash, David Lawler, David E. Grose, James B. Kite Jr., John C. Garrison and Jon H. Rateau, Case No. 08-cv-1025-M, U.S. District Court for the Western District of Oklahoma, filed September 25, 2008***

On September 25, 2008, a complaint was filed in the United States District Court for the Western District of Oklahoma, purportedly on QRCP s behalf, which named certain of QRCP s then current and former officers and directors as defendants. The factual allegations mirror those in the class actions described above, and the complaint asserts claims for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets, and unjust enrichment. The complaint seeks disgorgement, costs, expenses, and equitable and/or injunctive relief. On November 29, 2010, the action was dismissed with prejudice as part of the settlement referred to above.

***William Dean Enders, derivatively on behalf of nominal defendant Quest Energy Partners, L.P. v. Jerry D. Cash, David E. Grose, David C. Lawler, Gary Pittman, Mark Stansberry, J. Philip McCormick, Douglas Brent Mueller, Mid Continent Pipe & Equipment, LLC, Reliable Pipe & Equipment, LLC, RHB Global, LLC, RHB, Inc., Rodger H. Brooks, Murrell, Hall, McIntosh & Co. PLLP, and Eide Bailly LLP, Case No. CIV-09-752-M, U.S. District Court for the Western District of Oklahoma, filed July 17, 2009***

On July 17, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma, purportedly on QELP s behalf, which named certain of its then current and former officers and directors, external auditors and vendors. The factual allegations relate to, among other things, the transfers and lack of effective internal controls. The complaint asserts claims for breach of fiduciary duty, waste of corporate assets, unjust enrichment, conversion, disgorgement under the Sarbanes-Oxley Act of 2002, and

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

aiding and abetting breaches of fiduciary duties against the individual defendants and vendors and professional negligence and breach of contract against the external auditors. The complaint seeks monetary damages, disgorgement, costs and expenses and equitable and/or injunctive relief. It also seeks injunctive relief requiring QELP to take all necessary actions to reform and improve its corporate governance and internal procedures. On November 29, 2010, the action was dismissed with prejudice as part of the settlement referred to above.

**State Court Derivative Cases**

***Tim Bodeker, derivatively on behalf of nominal defendant Quest Resource Corporation v. Jerry Cash, David E. Grose, Bob G. Alexander, David C. Lawler, James B. Kite, John C. Garrison, Jon H. Rateau and William H. Damon III, Case No. CJ-2008-9042, District Court of Oklahoma County, State of Oklahoma, filed October 8, 2008***

***William H. Jacobson, derivatively on behalf of nominal defendant Quest Resource Corporation v. Jerry Cash, David E. Grose, David C. Lawler, James B. Kite, Jon H. Rateau, Bob G. Alexander, William H. Damon III, John C. Garrison, Murrell, Hall, McIntosh & Co., LLP, and Eide Bailly, LLP, Case No. CJ-2008-9657, District Court of Oklahoma County, State of Oklahoma, filed October 27, 2008***

***Amy Wulfert, derivatively on behalf of nominal defendant Quest Resource Corporation, v. Jerry D. Cash, David C. Lawler, Jon C. Garrison, John H. Rateau, James B. Kite Jr., William H. Damon III, David E. Grose, N. Malone Mitchell III, and Bryan Simmons, Case No. CJ-2008-9042 consolidated December 30, 2008, District Court of Oklahoma County, State of Oklahoma (Original Case No. CJ-2008-9624, filed October 24, 2008)***

The factual allegations in these petitions mirror those in the class actions discussed above. All three petitions assert claims for breach of fiduciary duty, abuse of control, gross mismanagement, and unjust enrichment. The *Jacobson* petition also asserts claims against the two auditing firms named in that suit for professional negligence and aiding and abetting the director defendants breaches of fiduciary duties. The *Wulfert* petition also asserts a claim against Mr. Bryan Simmons for aiding and abetting Mr. Cash s and Mr. Grose s breaches of fiduciary duties. The petitions seek damages, costs, expenses, and equitable relief. On March 26, 2009, the court consolidated these actions as *In re Quest Resource Corporation Shareholder Derivative Litigation*, Case No. CJ-2008-9042. In conjunction with the settlement of the securities and derivative cases, on January 26, 2011, an agreed order of dismissal was entered in the consolidated action.

**Royalty Owner Class Action**

***Hugo Spieker, et al. v. Quest Cherokee, LLC, Case No. 07-1225-MLB, U.S. District Court for the District of Kansas, filed August 6, 2007***

The Company was named as a defendant in a putative class action lawsuit filed by several royalty owners in the U.S. District Court for the District of Kansas. The putative class consists of all royalty and overriding royalty owners in the Kansas portion of the Cherokee Basin. Plaintiffs contend that the Company failed to properly make royalty payments by, among other things, paying royalties based on sale volumes rather than wellhead volumes, by allocating expenses in excess of actual costs, by improperly allocating production costs and marketing costs to royalty owners, and by failing to pay interest on royalty payments made late. The Company has filed an answer, denying plaintiffs claims.

The parties have participated in multiple mediation sessions with the most recent in January 2011, and continue to engage in settlement discussions. The parties have agreed to a period of limited discovery with another mediation to occur thereafter. If the matter cannot be resolved at that time, the case will proceed with general discovery, a class certification hearing, and a trial on the merits. The Company has recorded an accrual of $1.0 million related to this case although there can be no assurance that the amount accrued will be sufficient to cover any eventual loss from this litigation.

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**Litigation Related to Oil and Gas Leases**

***Billy Bob Willis, et al. v. Quest Resource Corporation, et al., Case No. CJ-09-063, District Court of Nowata County, State of Oklahoma, filed April 28, 2009***

***Larry Reitz, et al. v. Quest Resource Corporation, et al., Case No. CJ-09-076, District Court of Nowata County, State of Oklahoma, filed May 22, 2009***

The above-referenced lawsuits, which were filed in April and May 2009, respectively, have been consolidated to proceed as a single action. Plaintiffs are royalty interest owners located in Nowata and Craig counties. They allege that defendants have wrongfully deducted post-production costs from the plaintiffs royalties and have engaged in self-dealing contracts and agreements resulting in a less than market price for the gas production. Plaintiffs seek unspecified actual and punitive damages. Limited discovery has taken place. Trial will likely occur in October, 2011. The parties have participated in settlement discussions and a mediation which was held February 25, 2011. A second mediation is scheduled for March 9, 2011.

**Other Matters**

*Environmental Matters* As of December 31, 2010 and 2009, there were no known environmental or regulatory matters related to our operations which are reasonably expected to result in a material liability to us. Like other oil and gas producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Therefore it is extremely difficult to reasonably quantify future environmental related expenditures.

*Operating Lease Commitments* The Company has a leasing agreement for pipeline capacity that includes renewal options and options to increase capacity, which would also increase rentals. The initial term of this lease began June 1, 1992 and ended October 31, 2009. In April 2009, the term of this lease was extended to October 31, 2011. In December 2010, the Company elected to exercise a capacity lease reduction option in its leasing agreement reducing the lease capacity to 33,000 Dth from 90,000 Dth with an estimated reduction in lease payments of $1.1 Million in 2011.

We have lease agreements to obtain natural gas compressors as and when required. Terms of the leases on the gas compressors call for a minimum obligation of one year and are month to month thereafter.

In addition, we have operating leases for office space, warehouse facilities and office equipment expiring in various years through 2017.

Future minimum rental payments under all non-cancelable operating leases as of December 31, 2010, were as follows (in thousands):

| | |
|---|---|
| Year ending December 31, | |
| 2011 | $ 7,178 |

| | |
|---|---|
| 2012 | 2,111 |
| 2013 | 1,129 |
| 2014 | 932 |
| 2015 | 729 |
| Thereafter | 1,054 |
| Total minimum lease obligations | $ 13,133 |

Total rental expense under cancelable and non-cancelable operating leases was $2.5 million and $13.1 million for the periods from January 1 to March 5, 2010, and March 6 to December 31, 2010, and $17.3 million and $17.2 million for the years ended December 31, 2009 and 2008, respectively. Included in

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

rental expense for the periods from January 1 to March 5, 2010, and March 6 to December 31, 2010, and for the years ended December 31, 2009 and 2008 are $0.5 million, $1.3 million, $2.0 million and $3.1 million of expenses for the pipeline capacity lease discussed above, respectively.

*Financial Advisor Contracts* In February 2010, we extended an investment advisory service agreement that would have otherwise expired for an additional five months in exchange for monthly payments of $50,000. We also entered into an equity financing advisory agreement in February 2010 that resulted in payment of $4.3 million upon the successful restructuring of the Company s debt facilities and the investment from White Deer in September 2010. In July 2010, the Company entered into an investment advisory agreement in conjunction with its efforts to sell certain oil and gas properties in Appalachia (see Note 3). Upon closing of the first two phases of the asset sale in January 2011, the Company paid fees of $0.4 million to its investment advisor representing 1% of the gross sale price of the assets sold.

## Note 15 Supplemental Cash Flow Information

| | | Predecessor | | |
|---|---|---|---|---|
| | March 6 to December 31, 2010 | January 1 to March 5, 2010 | Year Ended December 31, 2009 | Year Ended December 31, 2008 |
| | (In thousands) | | | |
| Cash paid for interest | $ 10,699 | $ 2,686 | $ 19,293 | $ 21,813 |
| Cash paid for income taxes | | | | |
| **Noncash investing activity** | | | | |
| Equity securities received on the sale of oil and gas properties | 14,000 | | | |
| **Noncash financing activity** | | | | |
| Reduction of debt through conveyance of financial securities received from sale of oil and gas properties | 12,646 | | | |
| Issuance of preferred stock and warrants in lieu of cash dividends | 1,980 | | | |
| Accretion of discount on redeemable preferred stock | 327 | | | |

## Note 16 Related Party Transactions

During the period from 2005 to 2007, our former chief executive officer made certain unauthorized transfers, repayments and re-transfers of funds totaling $10.0 million to entities that he controlled. During 2009, under the terms of a settlement agreement reached in May 2009, the Company received approximately $2.4 million in cash, 60% of the controlled entity s interest in a natural gas well located in Louisiana and a landfill natural gas development project located in Texas, all of our former chief executive officer s equity interest in STP Newco, Inc. which owns certain oil producing properties in Oklahoma and other assets for a total estimated the net fair value of $3.4 million. During 2010, the Company recovered an additional $1.6 million in assets related to the misappropriation of which $1.1 million was received in cash.

**Note 17 Operating Segments**

The Company divides its operations into two reportable business segments:

*Production* The Company s production segment includes the acquisition, exploration, development, production and gathering of crude oil and natural gas.

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

*Pipeline* The Company s pipeline segment consists of a 1,120 mile interstate natural gas pipeline (the KPC Pipeline ), which transports natural gas from northern Oklahoma and western Kansas to Wichita and Kansas City.

Both of these segments are exclusively located in the continental United States, and each segment uses the same accounting policies as those described in the summary of significant accounting policies (see Note 2 Summary of Significant Accounting Policies). The Company s reportable segments are strategic business units that offer different products and services. Each segment is managed separately because each segment involves different products and marketing strategies. The Company does not allocate income taxes to its operating segments.

During the fourth quarter of 2010, the Company reclassified the operations and assets of its gathering system in the Cherokee Basin from its former natural gas pipelines segment to its production segment. The reclassification was prompted by, among other things, the expiration of the midstream services and gas dedication agreement between Bluestem Pipeline, LLC and QELP, the refinancing of its debt facilities during the third quarter of 2010, the legal restructuring of its subsidiaries and a change in management s approach to evaluating the business. The operating results and capital expenditures for the Company s segments presented below have been revised to reflect the segment change.

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Operating segment data for the periods indicated is as follows (in thousands):

| | Production | Pipeline | Total |
|---|---|---|---|
| **PostRock** | | | |
| **March 6 to December 31, 2010** | | | |
| Total revenues | $ 74,048 | $ 8,380 | $ 82,428 |
| Segment operating profit | $ 33,456 | $ 260 | $ 33,716 |
| Capital expenditures | $ 28,564 | $ 919 | $ 29,483 |
| Depreciation, depletion and amortization | $ 15,835 | $ 2,848 | $ 18,683 |
| Impairment | $ | $ | $ |
| **Predecessor** | | | |
| **January 1 to March 5, 2010** | | | |
| Total revenues | $ 19,735 | $ 1,749 | $ 21,484 |
| Segment operating profit | $ 7,516 | $ 49 | $ 7,565 |
| Capital expenditures | $ 2,270 | $ 567 | $ 2,837 |
| Depreciation, depletion and amortization | $ 3,574 | $ 590 | $ 4,164 |
| Impairment | $ | $ | $ |
| **Year Ended December 31, 2009** | | | |
| Total revenues | $ 87,653 | $ 18,428 | $ 106,081 |
| Segment operating profit (loss) | $ (222,839) | $ (50,071) | $ (272,910) |
| Capital expenditures | $ 8,762 | $ 797 | $ 9,559 |
| Depreciation, depletion and amortization | $ 39,438 | $ 8,364 | $ 47,802 |
| Impairment | $ 215,068 | $ 53,562 | $ 268,630 |
| **Year Ended December 31, 2008** | | | |
| Total revenues | $ 171,203 | $ 19,472 | $ 190,675 |
| Segment operating profit (loss) | $ (254,221) | $ 1,761 | $ (252,460) |
| Capital expenditures | $ 265,725 | $ 1,391 | $ 267,116 |
| Depreciation, depletion and amortization | $ 60,369 | $ 10,076 | $ 70,445 |
| Impairment | $ 298,861 | $ | $ 298,861 |
| **Identifiable assets** | | | |
| December 31, 2010(1) | $ 232,111 | $ 64,701 | $ 296,812 |
| December 31, 2009 | $ 128,548 | $ 155,107 | $ 283,655 |

(1) Reflects $77.2 million of the Company s gathering system assets reclassified to the full cost pool during the fourth quarter of 2010.

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The following table reconciles segment operating profit reported above to loss before income taxes and non-controlling interests (in thousands):

| | | | Predecessor | |
|---|---|---|---|---|
| | March 6 to December 31, 2010 | January 1 to March 5, 2010 | Years Ended December 31, 2009 | 2008 |
| Segment operating profit (loss) | $ 33,716 | $ 7,565 | $ (272,910) | $ (252,460) |
| General and administrative expenses | (20,705) | (5,735) | (41,723) | (28,269) |
| Recovery of (loss on) misappropriation of funds | 1,592 | | 3,412 | |
| Gain from derivative financial instruments | 47,870 | 25,246 | 48,122 | 66,145 |
| Interest expense, net | (20,137) | (5,336) | (29,329) | (25,373) |
| Gain on forgiveness of debt | 2,909 | | | |
| Other income (expense), net | (24) | (4) | 108 | 305 |
| Loss before income taxes and noncontrolling interests | $ 45,221 | $ 21,736 | $ (292,320) | $ (239,652) |

**Note 18 Profit Sharing Plan**

Substantially all of the Company s employees are covered by a profit sharing plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make contributions to the plan by electing to defer some of their compensation. The Company s match is discretionary; however, prior to 2009, it matched 100% of total contributions up to a total of five percent of annual compensation. Beginning in 2009, the matched contribution was reduced from five percent to three percent. Prior to July 1, 2009, the matching contribution vested using a graduated vesting schedule over six years of service. Beginning on July 1, 2009, the vesting schedule was reduced to a three year graduated vest. The Company made cash contributions to the plan of $0.1 million from January 1 to March 5, 2010, and $0.2 million from March 6 to December 31, 2010. During the years ended December 31, 2009 and 2008 the Company made cash contributions to the plan of $0.4 million and $0.6 million, respectively.

**Note 19 Subsequent Events**

The Company evaluated activity after December 31, 2010, until the date of issuance, for recognized and unrecognized subsequent events not discussed elsewhere in these footnotes and determined there were none.

**Note 20 Supplemental Financial Information Quarterly Financial Data (Unaudited)**

Summarized unaudited quarterly financial data for 2010 and 2009 are as follows (in thousands, except per share data):

| | Quarters Ended December 31, | Quarters Ended September 30, | Quarters Ended June 30, | March 6 to March 31 | January 1 to March 5 (Predecessor) |
|---|---|---|---|---|---|
| **2010** | | | | | |
| Total revenues | $ 23,451 | $ 25,323 | $ 23,826 | $ 9,828 | $ 21,484 |
| Operating income (loss)(1) | 12,173 | 4,462 | (2,676) | 644 | 1,830 |
| Net income (loss) | 9,609 | 28,189 | (9,587) | 17,010 | 21,736 |
| Net income (loss) per common share | | | | | |
| Basic | $ 0.91 | $ 3.47 | $ (1.19) | $ 2.12 | $ 0.37 |
| Diluted | $ 0.66 | $ 3.21 | $ (1.19) | $ 2.04 | $ 0.36 |

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

| | Quarters Ended | | | |
|---|---|---|---|---|
| | **December 31,** | **September 30,** | **June 30,** | **March 31,** |
| **2009 (Predecessor)** | | | | |
| Total revenues | $ 28,348 | $ 23,962 | $ 23,693 | $ 30,078 |
| Impairment(2) | 165,728 | | | 102,902 |
| Operating income (loss)(1)(3) | (174,516) | (18,416) | (6,617) | (111,672) |
| Net income (loss)(3) | (166,026) | (16,724) | (30,530) | (79,040) |
| Net income (loss) per common share | | | | |
| Basic | $ (2.01) | $ (0.36) | $ (0.57) | $ (1.62) |
| Diluted | $ (2.01) | $ (0.36) | $ (0.57) | $ (1.62) |

(1) Total revenue less total costs and expenses.

(2) The impairment charge of $102.9 million in the first quarter is related to the carrying value of oil and gas properties and the impairment charge of $165.7 million in the fourth quarter is related to the carrying value of the Company s gathering system and interstate pipeline assets.

(3) Fourth quarter of 2009 was impacted by the change in prices used in determining the Company s proved oil and gas reserves.

**Note 21 Supplemental Information on Oil and Gas Producing Activities (Unaudited)**

The supplementary, oil and gas data that follows is presented in accordance with FASB ASC 932 *Extractive Activities Oil and Gas* ( FASB ASC 932 ), and includes (1) capitalized costs, costs incurred and results of operations related to oil and gas producing activities, (2) net proved oil and gas reserves, and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves.

***Modernization of Oil and Gas Reporting***

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC s full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. We adopted these amended rules as of December 31, 2009.

Among the significant changes to reserve disclosures that have resulted from these amendments include:

*Pricing mechanism for oil and gas reserves estimation* The SEC s previous rules required proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves.

Price changes could be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

*Reasonable certainty* The SEC s previous definition of proved oil and gas reserves incorporated certain specific concepts such as lowest known hydrocarbons, which limited the ability to claim

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells.

Because the revised rules generally expand the definition of proved reserves, the Company had an increase of approximately 1.9 Bcfe of proved reserve estimates as of December 31, 2009.

*Unproved reserves* The SEC s previous rules prohibited disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves and must state whether the reserves are developed or undeveloped. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations.

*Net Capitalized Costs*

Aggregate capitalized costs related to oil and gas producing activities as of December 31, 2010 and 2009 are summarized as follows (in thousands):

| | 2010 | 2009 |
|---|---|---|
| Oil and gas properties and related leasehold costs | | |
| Proved | $ 319,966 | $ 205,199 |
| Unproved | 188 | 596 |
| | 320,154 | 205,795 |
| Accumulated depreciation, depletion and amortization | (203,666) | (165,317) |
| Net capitalized costs | $ 116,488 | $ 40,478 |

Unproved properties not subject to amortization consisted mainly of leaseholds acquired through acquisitions. The Company will continue to evaluate its unproved properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

*Costs Incurred*

Costs incurred in oil and gas property acquisition, exploration and development activities that have been capitalized for the years ended December 31, 2010, 2009 and 2008 summarized as follows (in thousands):

| | 2010(a) | 2009 | 2008 |
|---|---|---|---|
| Proved property acquisition costs | $ 1,364 | $ 1,293 | $ 152,118(b) |
| Unproved property acquisition costs | 828 | 705 | 18,945 |
| Exploration costs | | 128 | 1,273 |
| Development costs | 27,396 | 5,087 | 58,070 |
| | $ 29,588 | $ 7,213 | $ 230,406 |

(a) Costs incurred for the period from January 1 to March 5, 2010, were $2.1 million.

(b) Includes the acquisition of the PetroEdge & Seminole County, Oklahoma properties.

*Oil and Gas Reserve Quantities*

The following reserve schedule was developed by the Company s reserve engineers and sets forth the changes in estimated quantities for its proved reserves, all of which are located in the United States. The Company retained Cawley, Gillespie & Associates, Inc., independent reserve engineers, to perform the annual year-end independent evaluation of proved reserves.

Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upwards or downward) to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

As discussed in Note 4, during the fourth quarter of 2010, the Company reclassified the operations and assets of its gathering system in the Cherokee Basin from its former natural gas pipelines segment to its production segment. Prior to the reclassification, the determination of the Company s oil and gas reserves included gathering costs based on the gathering rate charged under the midstream services and gas dedication agreement between Bluestem Pipeline, LLC and QELP. The agreement was no longer in effect subsequent to the restructuring of the Company s credit facilities at the end of the third quarter in 2010. Gathering costs included in the Company s oil and gas reserves as of

December 31, 2010, are now based on projected operating expenses of the gathering system which are lower than the costs under the midstream services and gas dedication agreement. In addition, future oil and gas development costs now include anticipated capital

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

expenditures associated with the gathering system. These changes are reflected in the rollforward of the Company s reserves for 2010.

| | Gas Mcf | Oil Bbls |
|---|---|---|
| Proved reserves | | |
| Balance, December 31, 2007 | 210,923,406 | 36,556 |
| Purchase of reserves in place | 94,727,687 | 1,560,946 |
| Extensions, discoveries, and other additions | 13,897,600 | |
| Sale of reserves | (4,386,200) | |
| Revisions of previous estimates(1) | (123,204,433) | (833,070) |
| Production | (21,328,687) | (69,812) |
| Balance, December 31, 2008 | 170,629,373 | 694,620 |
| Purchase of reserves in place | 142,985 | 34,905 |
| Extensions, discoveries, and other additions | 62,067 | |
| Sale of reserves | | |
| Revisions of previous estimates | (79,724,789) | 177,528 |
| Production | (21,235,065) | (83,015) |
| Balance, December 31, 2009 | 69,874,571 | 824,038 |
| Purchase of reserves in place | 10,842 | |
| Extensions, discoveries, and other additions | 574,200 | 11,851 |
| Sale of reserves | (13,016,672) | |
| Revisions of previous estimates(2) | 92,244,096 | (15,040) |
| Production | (19,225,006) | (76,583) |
| Balance, December 31, 2010 | 130,462,031 | 744,266 |
| Proved developed reserves | | |
| Balance, December 31, 2008 | 136,544,572 | 682,031 |
| Balance, December 31, 2009 | 62,135,258 | 785,345 |
| Balance, December 31, 2010(2) | 116,951,438 | 733,774 |

(1) Lower prices and projected increases in expected gathering costs at December 31, 2008 as compared to December 31, 2007 reduced the economic lives of the underlying oil and gas properties and thereby decreased the estimated future reserves. Additionally, estimated proved reserves acquired from PetroEdge in 2008 decreased approximately 35.5 Bcfe due to the decrease in natural gas prices between the date of the PetroEdge acquisition and December 31, 2008 and approximately 43.2 Bcfe, as a result of further technical analysis of the estimated PetroEdge reserves.

(2) Improved prices and lower costs in 2010 resulted in an increase in reserves. Costs were lower primarily due to the decrease in gathering costs discussed above.

*Standardized Measure of Discounted Future Net Cash Flows*

The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2010, 2009 and 2008 in accordance with FASB ASC 932 which requires the use of a 10% discount rate. Future income taxes are based on year-end

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**POSTROCK ENERGY CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

statutory rates. This information is not the fair market value, nor does it represent the expected present value of future cash flows of our proved oil and gas reserves (in thousands).

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Future cash inflows | $ 617,947 | $ 311,831 | $ 898,214 |
| Future production costs | 335,688 | 202,645 | 570,142 |
| Future development costs | 26,941 | 17,398 | 60,318 |
| Future income tax expense | 14,937 | | |
| Future net cash flows | 240,381 | 91,788 | 267,754 |
| 10% annual discount for estimated timing of cash flows | 81,120 | 41,229 | 103,660 |
| Standardized measure of discounted future net cash flows related to proved reserves | $ 159,261 | $ 50,559 | $ 164,094 |

Future cash inflows are computed by applying year-end prices (2008) or a twelve-month average price (for 2009 and 2010), adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of our derivative instruments. See the following table for oil and gas prices as of the periods indicated.

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Crude oil price per Bbl | $ 79.43 | $ 61.18 | $ 44.60 |
| Natural gas price per Mmbtu | $ 4.38 | $ 3.87 | $ 5.71 |

The principal changes in the standardized measure of discounted future net cash flows relating to proven oil and gas properties were as follows (in thousands):

| | As of December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Present value, beginning of period | $ 50,559 | $ 164,094 | $ 286,177 |
| Net changes in prices and production costs | 23,107 | (35,203) | (122,702) |
| Net changes in future development costs | (17,927) | 20,727 | (4,247) |
| Previously estimated development costs incurred | 17,515 | 5,292 | 66,060 |
| Sales of oil and gas produced, net | (40,962) | (46,442) | (103,826) |
| Extensions and discoveries | 895 | 50 | 15,986 |
| Purchases of reserves in-place | 15 | 283 | 119,733 |
| Sales of reserves in-place | (18,041) | | (5,045) |

| | | | |
|---|---|---|---|
| Revisions of previous quantity estimates | 127,723 | (63,230) | (147,464) |
| Net change in income taxes | (12,037) | | 36,360 |
| Accretion of discount | 6,660 | 17,576 | 31,804 |
| Timing differences and other(a) | 21,754 | (12,588) | (8,742) |
| Present value, end of period | $ 159,261 | $ 50,559 | $ 164,094 |

(a) The change in timing differences and other are related to revisions in our estimated time of production and development.

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## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized this 3rd day of March, 2011.

POSTROCK ENERGY CORPORATION

/s/ David C. Lawler
David C. Lawler
*Chief Executive Officer and President*

## POWER OF ATTORNEY

By signing this Annual Report on Form 10-K below, I hereby appoint each of David C. Lawler and Jack T. Collins, as my attorney-in-fact to sign any and all amendments to this Annual Report on Form 10-K on my behalf, and to file this Annual Report on Form 10-K (including all exhibits and other documents related to the Annual Report on Form 10-K) with the Securities and Exchange Commission. I authorize each of my attorneys-in-fact to (1) appoint a substitute attorney-in-fact for himself and (2) perform any actions that he believes are necessary or appropriate to carry out the intention and purpose of this Power of Attorney. I ratify and confirm all lawful actions taken directly or indirectly by my attorneys-in-fact and by any properly appointed substitute attorneys-in-fact.

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.

| Name | Capacity | Date |
|---|---|---|
| /s/ David C. Lawler<br>David C. Lawler | Chief Executive Officer and President and Director (Principal Executive Officer) | March 3, 2011 |
| /s/ Jack T. Collins<br>Jack T. Collins | Chief Financial Officer (Principal Financial Officer) | March 3, 2011 |
| /s/ David J. Klvac<br>David J. Klvac | Chief Accounting Officer (Principal Accounting Officer) | March 3, 2011 |
| /s/ Duke R. Ligon<br>Duke R. Ligon | Chairman of the Board | March 3, 2011 |
| /s/ Nathan M. Avery<br>Nathan M. Avery | Director | March 3, 2011 |

| | | |
|---|---|---|
| /s/ William H. Damon III | Director | March 3, 2011 |
| William H. Damon III | | |
| /s/ Thomas J. Edelman | Director | March 3, 2011 |
| Thomas J. Edelman | | |
| /s/ Gabriel Hammond | Director | March 3, 2011 |
| Gabriel Hammond | | |

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| Name | Capacity | Date |
|---|---|---|
| /s/ J. Philip McCormick | Director | March 3, 2011 |
| J. Philip McCormick | | |
| /s/ Gary M. Pittman | Director | March 3, 2011 |
| Gary M. Pittman | | |
| /s/ Jon H. Rateau | Director | March 3, 2011 |
| Jon H. Rateau | | |
| /s/ James E. Saxton Jr. | Director | March 3, 2011 |
| James E. Saxton Jr. | | |
| /s/ Daniel Spears | Director | March 3, 2011 |
| Daniel Spears | | |
| /s/ Mark A. Stansberry | Director | March 3, 2011 |
| Mark A. Stansberry | | |

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## INDEX TO EXHIBITS

| Exhibit No. | Description |
|---|---|
| 2.1* | Agreement and Plan of Merger, dated as of July 2, 2009, by and among PostRock Energy Corporation ( PostRock ), Quest Resource Corporation ( QRCP ), Quest Midstream Partners, L.P., Quest Energy Partners, L.P., Quest Midstream GP, LLC, Quest Energy GP, LLC, Quest Resource Acquisition Corp., Quest Energy Acquisition, LLC, Quest Midstream Holdings Corp. and Quest Midstream Acquisition, LLC (incorporated herein by reference to Exhibit 2.1 to QRCP s Current Report on Form 8-K filed on July 7, 2009). |
| 2.2* | First Amendment, dated as of October 2, 2009, to the Agreement and Plan of Merger, dated as of July 2, 2009 by and among PostRock, QRCP, Quest Midstream Partners, L.P., Quest Energy Partners, L.P., Quest Midstream GP, LLC, Quest Energy GP, LLC, Quest Resource Acquisition Corp., Quest Energy Acquisition, LLC, Quest Midstream Holdings Corp. and Quest Midstream Acquisition, LLC (incorporated herein by reference to Exhibit 2.1 to QRCP s Current Report on Form 8-K filed on October 8, 2009). |
| 2.3* | Purchase and Sale Agreement, dated as of December 24, 2010, by and among Quest Eastern Resource LLC, PostRock MidContinent Production, LLC, Magnum Hunter Resources Corporation and Triad Hunter, LLC (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a confidential treatment request under Rule 24b-2 of the Securities Exchange Act of 1934, as amended) (incorporated herein by reference to Exhibit 2.1 to PostRock s Current Report on Form 8-K filed on January 21, 2011). |
| 3.1* | Restated Certificate of Incorporation of PostRock (incorporated herein by reference to Exhibit 3.1 to PostRock s Current Report on Form 8-K filed on March 10, 2010). |
| 3.2* | Bylaws of PostRock (incorporated herein by reference to Exhibit 3.2 to PostRock s Current Report on Form 8-K filed on March 10, 2010). |
| 4.1* | Specimen of certificate for shares of Common Stock of PostRock (incorporated herein by reference to Exhibit 4.1 to Amendment No. 1 to PostRock s Registration Statement on Form S-4 filed on December 17, 2009, Registration No. 333-162366 (the Form S-4 ). |
| 4.2* | Certificate of Designations for the Series A Cumulative Redeemable Preferred Stock (incorporated herein by reference to Exhibit 4.1 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 4.3* | Certificate of Designations for the Series B Voting Preferred Stock (incorporated herein by reference to Exhibit 4.2 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 4.4* | Form of Warrant (incorporated herein by reference to Exhibit 4.3 to PostRock s Current Report on Form 8-K filed on September 3, 2010). |
| 10.1* | Securities Purchase Agreement dated September 2, 2010 among PostRock, White Deer Energy L.P., White Deer Energy TE L.P., and White Deer Energy FI L.P. (incorporated herein by reference to Exhibit 10.1 to PostRock s Current Report on Form 8-K filed on September 3, 2010). |
| 10.2* | Registration Rights Agreement dated September 21, 2010, among PostRock and White Deer Energy L.P., White Deer Energy TE L.P. and White Deer Energy FI L.P. (incorporated herein by reference to Exhibit 10.1 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.3* | Master Debt Restructuring Agreement dated September 2, 2010 among PostRock, PostRock Energy Services Corporation, PostRock Midcontinent Production, LLC, PostRock Midstream, LLC, Bluestem Pipeline, LLC, Quest Cherokee, LLC, the lenders party to the First Lien Credit Agreement signatory thereto, Royal Bank of Canada, as administrative agent and collateral agent for the First Lien Lenders, the lenders party to the Second Lien Credit Agreement signatory thereto, and Royal Bank of Canada, as administrative agent and collateral agent for the Second Lien Lenders, the lenders party to the |

| | |
|---|---|
| | Bluestem Credit Agreement signatory thereto, Royal Bank of Canada, as administrative agent and collateral agent for the Bluestem Lenders, the lender party to the Holdco Credit Agreement signatory thereto, and Royal Bank of Canada, as administrative agent and collateral agent for the Holdco Lender (incorporated herein by reference to Exhibit 10.3 to PostRock s Current Report on Form 8-K filed on September 3, 2010). |
| 10.4* | Loan Transfer Agreement among PostRock Energy Services Corporation, PostRock MidContinent Production, LLC, PostRock KPC Pipeline, LLC and Royal Bank of Canada, as Administrative Agent and Collateral Agent, dated September 21, 2010 (incorporated herein by reference to Exhibit 10.9 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |

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| Exhibit No. | Description |
|---|---|
| 10.5* | Loan Transfer Agreement among PostRock Energy Services Corporation, PostRock MidContinent Production, LLC and Royal Bank of Canada, as Administrative Agent, dated as of September 21, 2010 (incorporated herein by reference to Exhibit 10.10 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.6* | Second Amended and Restated Credit Agreement, dated September 21, 2010, among PostRock Energy Services Corporation and PostRock MidContinent Production, LLC, as Borrowers, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated herein by reference to Exhibit 10.3 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.7* | Amended and Restated Intercreditor and Collateral Agency Agreement, dated September 21, 2010, among Royal Bank of Canada, BP Corporation North America Inc., and PostRock Energy Services Corporation and PostRock MidContinent Production, LLC, as Borrowers (incorporated herein by reference to Exhibit 10.4 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.8* | Amended and Restated Pledge and Security Agreement among PostRock Energy Services Corporation, PostRock MidContinent Production, LLC, STP Newco, Inc. and Quest Transmission Company, LLC and the Collateral Agent dated September 21, 2010 (incorporated herein by reference to Exhibit 10.5 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.9* | Amended and Restated Guaranty, dated September 21, 2010, executed by PostRock in favor of Royal Bank of Canada, as Administrative Agent (incorporated herein by reference to Exhibit 10.6 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.10* | Guaranty (Subsidiary) executed by STP Newco, Inc. and Quest Transmission Company, LLC, dated September 21, 2010 (incorporated herein by reference to Exhibit 10.7 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.11* | Release and Termination of Guaranties by Royal Bank of Canada, as Administrative Agent and Collateral Agent, effective as of September 21, 2010, in favor of each of PostRock Energy Services Corporation, STP Newco, Inc. and PostRock MidContinent Production, LLC (incorporated herein by reference to Exhibit 10.17 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.12* | Second Amended and Restated Credit Agreement, dated September 21, 2010, among PostRock Energy Services Corporation and PostRock KPC Pipeline, LLC, as Borrowers, the Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated herein by reference to Exhibit 10.8 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.13* | Intercreditor and Collateral Agency Agreement between Royal Bank of Canada and PostRock KPC Pipeline, LLC, as obligor, dated September 21, 2010 (incorporated herein by reference to Exhibit 10.11 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.14* | Amended and Restated Pledge and Security Agreement, dated as of September 21, 2010, by and between PostRock KPC Pipeline, LLC and the Collateral Agent (incorporated herein by reference to Exhibit 10.12 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.15* | Pledge and Security Agreement, dated as of September 21, 2010, by and between PostRock Energy Services Corporation and the Collateral Agent (incorporated herein by reference to Exhibit 10.13 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.16* | Amended and Restated Guaranty, dated as of September 21, 2010, executed by PostRock in favor of Royal Bank of Canada, as Administrative Agent (incorporated herein by reference to Exhibit 10.14 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.17* | Release and Termination of Guaranties by Royal Bank of Canada, as Administrative Agent and Collateral Agent, effective as of September 21, 2010, in favor of each of PostRock Energy Services Corporation, Quest Transmission Company, LLC and PostRock KPC Pipeline, LLC (incorporated |

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|---|---|
| | herein by reference to Exhibit 10.18 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.18* | Assumption Agreement, dated as of September 21, 2010, by and between PostRock Energy Services Corporation and Quest Eastern Resource LLC (incorporated herein by reference to Exhibit 10.15 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |

| Exhibit No. | Description |
|---|---|
| 10.19* | Third Amended and Restated Credit Agreement dated September 21, 2010, among Quest Eastern Resource LLC, as the Borrower, the lender party thereto and Royal Bank of Canada, as Administrative Agent and Collateral Agent (incorporated herein by reference to Exhibit 10.19 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.20 | First Amendment to Third Amended and Restated Credit Agreement, dated as of February 21, 2011, among Quest Eastern Resources LLC, as the Borrower, the lender party thereto and Royal Bank of Canada, as Administrative Agent and Collateral Agent. |
| 10.21 | Consent and Reaffirmation of PostRock Energy Services Corporation and PostRock, dated February 21, 2011. |
| 10.22* | Pledge and Security Agreement executed by Quest Eastern Resource LLC, dated September 21, 2010 (incorporated herein by reference to Exhibit 10.20 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.23* | Pledge and Security Agreement executed by PostRock Energy Services Corporation, dated September 21, 2010 (incorporated herein by reference to Exhibit 10.21 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.24* | Release and Termination of Guaranties, Pledge and Security Agreements and Account Control Agreements by Royal Bank of Canada, as Administrative Agent and Collateral Agent, effective as of September 21, 2010, in favor of each of Quest Eastern Resource LLC, PostRock Energy Services Corporation and PostRock MidContinent Production, LLC (incorporated herein by reference to Exhibit 10.16 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.25* | Asset Sale Agreement, dated as of September 21, 2010, by and between PostRock and Royal Bank of Canada (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a confidential treatment request under Rule 24b-2 of the Securities Exchange Act of 1934, as amended) (incorporated herein by reference to Exhibit 10.9 to Amendment No. 1 to PostRock s Quarterly Report on Form 10-Q/A for the period ended September 30, 2010, filed on January 24, 2011). |
| 10.26* | Registration Rights Agreement dated March 5, 2010, between PostRock, Alerian Opportunity Partners IV, LP, Alerian Opportunity Partners IX, L.P., Alerian Focus Partners, LP, Alerian Capital Partners, LP, Swank MLP Convergence Fund, LP, Swank Investment Partners, LP, The Cushing MLP Opportunity Fund I, LP, The Cushing GP Strategies Fund, LP, Bel Air MLP Energy Infrastructure Fund, LP, Tortoise Capital Resources Corporation and Tortoise North American Energy Corporation (incorporated herein by reference to Exhibit 10.1 to PostRock s Current Report on Form 8-K filed on March 10, 2010). |
| 10.27* | Form of QRCP s Indemnification Agreement for Directors (incorporated herein by reference to Exhibit 10.10 to QRCP s Annual Report on Form 10-K filed on June 3, 2009). |
| 10.28* | Form of QRCP s Indemnification Agreement for Officers (incorporated herein by reference to Exhibit 10.11 to QRCP s Annual Report on Form 10-K filed on June 3, 2009). |
| 10.29* | Employment Agreement dated April 10, 2007 between QRCP and David Lawler (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on April 13, 2007). |
| 10.30* | First Amendment to Employment Agreement, dated October 20, 2008, between QRCP and David Lawler (incorporated herein by reference to Exhibit 10.2 to QRCP s Current Report on Form 8-K filed on October 24, 2008). |
| 10.31* | Nonqualified Stock Option Agreement, dated October 20, 2008, between QRCP and David Lawler (incorporated herein by reference to Exhibit 10.4 to QRCP s Current Report on Form 8-K filed on October 24, 2008). |
| 10.32* | |

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| | Assignment and Amendment Agreement dated March 5, 2010, between PostRock, QRCP and David C. Lawler (incorporated herein by reference to Exhibit 10.11 to PostRock s Current Report on Form 8-K filed on March 10, 2010). |
| 10.33* | Employment Agreement dated December 3, 2007 between QRCP and Jack T. Collins (incorporated herein by reference to Exhibit 10.28 to QRCP s Annual Report on Form 10-K filed on March 10, 2008). |
| 10.34* | First Amendment to Employment Agreement, dated October 23, 2008, between QRCP and Jack Collins (incorporated herein by reference to Exhibit 10.3 to QRCP s Current Report on Form 8-K filed on October 24, 2008). |

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| Exhibit No. | Description |
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| 10.35* | Second Amendment to Employment Agreement, dated August 28, 2009, between QRCP and Jack Collins (incorporated herein by reference to Exhibit 10.5 to QRCP s Quarterly Report on Form 10-Q filed on November 5, 2009). |
| 10.36* | Assignment and Amendment Agreement dated March 5, 2010, between PostRock, QRCP and Jack Collins (incorporated herein by reference to Exhibit 10.13 to PostRock s Current Report on Form 8-K filed on March 10, 2010). |
| 10.37* | Nonqualified Stock Option Agreement, dated October 23, 2008, between QRCP and Jack Collins (incorporated herein by reference to Exhibit 10.5 to QRCP s Current Report on Form 8-K filed on October 24, 2008). |
| 10.38* | Employment Agreement dated March 21, 2007 between QRCP and Richard Marlin (incorporated herein by reference to Exhibit 10.30 to QRCP s Annual Report on Form 10-K filed on March 10, 2008). |
| 10.39* | First Amendment to Employment Agreement, dated December 29, 2008, between QRCP and Richard Marlin (incorporated herein by reference to Exhibit 10.32 to QRCP s Annual Report on Form 10-K filed on June 3, 2009). |
| 10.40* | Assignment and Amendment Agreement dated March 5, 2010, between PostRock, QRCP and Richard Marlin (incorporated herein by reference to Exhibit 10.14 to PostRock s Current Report on Form 8-K filed on March 10, 2010). |
| 10.41* | Office Lease dated May 31, 2007 between QRCP and Oklahoma Tower Realty Investors, L.L.C. (incorporated herein by reference to Exhibit 10.5 to QRCP s Quarterly Report on Form 10-Q filed on August 9, 2007). |
| 10.42* | Assignment and Assumptions of Leases, dated as of February 28, 2008, by and between Chesapeake Energy Corporation and QRCP (incorporated herein by reference to Exhibit 10.7 to QRCP s Quarterly Report on Form 10-Q filed on May 12, 2008). |
| 10.43* | First Amendment to Office Lease, dated as of February 7, 2008, by and between Cullen Allen Holdings L.P. and Quest Midstream Partners, L.P. (incorporated herein by reference to Exhibit 10.6 to QRCP s Quarterly Report on Form 10-Q filed on May 12, 2008). |
| 10.44* | Form of Indemnification Agreement for Officers and Directors (incorporated herein by reference to Exhibit 10.2 to PostRock s Current Report on Form 8-K filed on September 23, 2010). |
| 10.45* | PostRock 2010 Long-Term Incentive Plan (incorporated herein by reference to Annex B to the joint proxy statement/prospectus that is a part of PostRock s Registration Statement on Form S-4/A filed on February 2, 2010). |
| 10.46* | Nonqualified Stock Option Agreement, dated August 15, 2007, between QRCP and William Damon III (incorporated herein by reference to Exhibit 10.75 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009). |
| 10.47* | Restricted Shares Award Agreement dated April 26, 2010, between PostRock and David C. Lawler (incorporated herein by reference to Exhibit 10.16 to PostRock s Quarterly Report on From 10-Q filed on May 13, 2010). |
| 10.48* | PostRock Management Incentive Program (incorporated herein by reference to Exhibit 10.1 to PostRock s Current Report on Form 8-K filed on April 6, 2010). |
| 10.49* | PostRock 2010 Long-Term Incentive Plan Form of Bonus Share Award Agreement (incorporated herein by reference to Exhibit 10.1 to PostRock s Current Report on Form 8-K filed on August 10, 2010). |
| 10.50* | PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (immediate vesting). |
| 10.51* | |

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| | PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (one-year vesting). |
| 10.52* | PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (multi-year vesting) (incorporated herein by reference to Exhibit 10.2 to PostRock s Current Report on Form 8-K filed on August 10, 2010). |
| 10.53* | PostRock 2010 Long-Term Incentive Plan Form of Restricted Share Award Agreement (multi-year vesting) (incorporated herein by reference to Exhibit 10.3 to PostRock s Current Report on Form 8-K filed on August 10, 2010). |

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| Exhibit No. | Description |
|---|---|
| 10.54* | PostRock 2010 Long-Term Incentive Plan Form of Restricted Share Unit Award Agreement (multi-year vesting) (incorporated herein by reference to Exhibit 10.4 to PostRock s Current Report on Form 8-K filed on August 10, 2010). |
| 10.55* | Summary of certain director compensation matters (incorporated by reference to Exhibit 10.11 to PostRock s Quarterly Report on Form 10-Q filed November 10, 2010). |
| 21.1 | List of Subsidiaries. |
| 23.1 | Consent of Cawley, Gillespie & Associates, Inc. |
| 23.2 | Consent of UHY, LLP. |
| 31.1 | Certification by principal executive officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | Certification by principal financial officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | Certification by principal executive officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2 | Certification by principal financial officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 99.1 | Report of Cawley, Gillespie & Associates, Inc. |

* Incorporated by reference.

Management contracts and compensatory plans and arrangements required to be filed as Exhibits pursuant to Item 14(a) of this report.

PLEASE NOTE: Pursuant to the rules and regulations of the Securities and Exchange Commission, we have filed or incorporated by reference the agreements referenced above as exhibits to this Annual Report on Form 10-K. The agreements have been filed to provide investors with information regarding their respective terms. The agreements are not intended to provide any other factual information about PostRock or its business or operations. In particular, the assertions embodied in any representations, warranties and covenants contained in the agreements may be subject to qualifications with respect to knowledge and materiality different from those applicable to investors and may be qualified by information in confidential disclosure schedules not included with the exhibits. These disclosure schedules may contain information that modifies, qualifies and creates exceptions to the representations, warranties and covenants set forth in the agreements. Moreover, certain representations, warranties and covenants in the agreements may have been used for the purpose of allocating risk between the parties, rather than establishing matters as facts. In addition, information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the respective agreement, which subsequent information may or may not be fully reflected in our public disclosures. Accordingly, investors should not rely on the representations, warranties and covenants in the agreements as characterizations of the actual state of facts about PostRock or its business or operations on the date hereof.