PostRock Energy Corp
Form 10-K
March 08, 2012
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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, 2011

Commission file number: 001-34635

PostRock Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

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 þ No ¨

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. ¨

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	¨ (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 ¨ No þ

The aggregate market value of common stock held by non-affiliates of the registrant at June 30, 2011, was approximately $48.0 million, based upon the closing price of $5.83 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, 2012, was approximately $45.8 million, based upon the closing price of $3.78 per share. There were 12,115,570 shares of common stock outstanding on that date.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2012 Annual Meeting of Stockholders are incorporated by reference in Part III.

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GLOSSARY

The following abbreviations are used in this report:

Bbl	Barrel
Bbls/d	Barrels per day
MMBbl	Million 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 commodity prices in early 2012, the price for an Mcf of natural gas is approximately 1/40th the price for a barrel of oil.
MMcfe	Million cubic feet equivalent
MMcfe/d	Million cubic feet equivalent per day
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) is a Delaware corporation formed in 2009. It was formed to combine its predecessor entities, Quest Resource Corporation, Quest Energy Partners, L.P. and Quest Midstream Partners, L.P. (collectively, the Predecessors) into a single entity. In March 2010, PostRock completed the combination of these entities (the Recombination). Unless the context requires otherwise, references to we, us and our refer to PostRock from the date of the Recombination and to the Predecessors on a consolidated basis prior thereto.

We are an independent oil and gas 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 (the Basin), a 15-county region in southeastern Kansas and northeastern Oklahoma. We also have minor oil producing properties in Oklahoma and 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.

Production

PostRock s 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 1,400 feet. In order to understand how to improve our wells performance, we have been conducting and continue to conduct 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. The studies have enabled us to better understand our production curves and production areas. We are also evaluating the possibility of finding oil and gas reserves in other geologic horizons.

At December 31, 2011, our Cherokee Basin assets consisted of approximately 2,773 gross and 2,758 net wells capable of production. These wells are on approximately 347,364 net acres of leasehold classified as developed. In addition, we have approximately 117,499 net acres classified as undeveloped in the Cherokee Basin. During 2011, our net production from these wells was an average of 48.5 Mmcfe/d. At year end, our reservoir engineers attributed 109.9 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 one intrastate and three 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, throughput on the system averaged 62.5 Mmcf/d of which approximately 3.6 MMcf/d and 10.6 MMcf/d was attributable to third parties and to our royalty owners, respectively. Third-party gathering contracts generally permit us to retain 20% to 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 74 leased compressors totaling approximately 51,000 horsepower and six CO_2 amine treating facilities. The system has an estimated throughput capacity of approximately 85 Mmcf/d. Based on net production in 2011, we believe we are the largest producer of gas in the Cherokee Basin with net production equal to approximately two times that of Constellation Energy Partners LLC (CEP), the second largest producer in the Basin. We also believe that we have the largest gathering system in the Basin.

At December 31, 2011, our Oklahoma oil assets consisted of approximately 24 gross and 22.5 net wells capable of production. These wells are on approximately 1,360 net acres of leasehold classified as developed. In

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addition, we have approximately 120 net acres classified as undeveloped in central Oklahoma. During 2011, net production from these wells averaged 133 Bbls/d. At year end, our reservoir engineers attributed 0.8 MMBbl of crude oil and 203 Mmcf of natural gas, or a total of 5.1 Bcfe, of estimated net proved reserves to these properties.

As discussed below, we sold the majority of our Appalachian Basin assets in late 2010 and during the first half of 2011. Subsequent to the sale, our remaining assets consist of approximately 488 gross and 457 net wells capable of production. These wells are on approximately 8,870 net acres of leasehold classified as developed. In addition, we have approximately 24,871 net acres classified as undeveloped in the Appalachian Basin. During 2011, net production from our remaining wells was an average of 1.9 Mmcfe/d. At year end, our reservoir engineers attributed 9.7 Bcfe of estimated net proved reserves to these properties.

We also have a 141.1 mile gathering system in the Appalachian Basin. The system is connected to one interstate pipeline. At December 31, 2011, this system had an average throughput of approximately 2.1 Mmcf/d of which approximately 1.6 Mmcf/d was attributable to our net production with the remaining 0.5 Mmcf/d attributable to our royalty or joint interest owners. All of our gas produced 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 West Virginia. The sale enabled us to reduce debt and focus on the Cherokee Basin. The sale closed in three phases for $44.6 million. The first phase closed in December 2010 for $28 million, and the next two phases closed in January and June 2011 for a combined $16.6 million. The amount received for the first and second phases was paid half in cash and half in MHR common stock, while the amount received for the third phase was paid entirely in cash. Of the proceeds received, $6.4 million was set aside in escrow to cover potential claims for indemnity and title defects. If all of the amounts in escrow are released, we would receive a total of $1.5 million and the remaining amount would be released to our lender and a third party.

CEP Investment. During 2011, we acquired from Constellation Energy Group, Inc. (CEG) a 26.4% voting interest in CEP and the right to appoint two directors to CEP s Board. The investment was consummated in two separate transactions. The first transaction, which included a 14.9% voting interest, closed in August 2011 for $6.9 million in cash and $4.6 million in PostRock equity, while the second transaction, for an additional 11.5% voting interest, closed in December 2011 for $6.1 million in cash. The investment is described further within Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report on Form 10-K. CEP is focused on the acquisition, development and production of oil and natural gas properties as well as related midstream assets. Because PostRock and CEP each have the majority of their assets in the Cherokee Basin of Kansas and Oklahoma, the investment was made in an attempt to work with CEP to explore opportunities to reduce costs and enhance value for the companies respective investors. Except where expressly noted, references to reserves, results, production, prices and other statistics included in this Annual Report on Form 10-K exclude amounts related to our interest in CEP.

In June 2011, we agreed to purchase CEG s roughly 26.4% interest in CEP. Closing was contingent on the approval of CEP s Board of Managers. After CEP s Board declined to consider the request, we terminated the agreement, purchasing approximately a 14.9% interest in CEP in August 2011. The less than 15% stake avoided triggering certain anti-takeover provisions of the Delaware statutes. When CEG decided to sell the remainder of their position in December 2011, we elected to purchase it despite the Delaware statute. The purchase increased our ownership position to approximately 26.4%. Under the Delaware statute, a business combination or other corporate transaction with CEP may now not be possible prior to December 2014. Despite their prior lack of support, we continue to hope the Board and management of CEP will work with us to explore opportunities for increased efficiency in the Cherokee Basin. The importance of efficiency has obviously increased dramatically as gas prices languish below $3.00/Mcf in early 2012. Unfortunately, while CEP s Board has indicated a willingness to discuss these matters, they have insisted that the substance and even the existence of any such discussion remain secret. To date, we have been unwilling to keep the overall status of any discussions from our shareholders.

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Interstate Pipeline

The KPC Pipeline is one of five pipelines capable of delivering gas to Kansas City. It has a throughput capacity of approximately 160 Mmcf/d. The pipeline includes three compressor stations with a total of 14,680 horsepower. The 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 pipeline is regulated by the Federal Energy Regulatory Commission (FERC).

The KPC Pipeline continues to be underutilized, but throughput, revenue and operating expenses in the past year continue to improve. We are working to increase throughput by creating additional service options for gas suppliers and consumers and pursuing additional pipeline interconnects to provide customers greater optionality for gas supply and market. Throughput in 2011 increased 10.1% from the prior year.

We are currently exploring strategic alternatives for the KPC Pipeline. Transactions being considered include a sale or joint venture that may involve conversion of part of the line to crude oil service. We have retained a financial advisor to assist in the process.

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 in the Cherokee Basin which 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 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 principal formations we target include the Mulky, the Weir-Pittsburgh and the Riverton. These coal seams are blanket type deposits, which extend across large areas of the Basin. Each seam is generally 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 for more efficient dewatering, which has reduced the amount of time it takes for our CBM wells to achieve peak production 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

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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 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 our producing formations range in depth from 1,500 feet to approximately 6,500 feet. 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

With the significant reduction in natural gas prices at the end of 2011, continuing into 2012 and expected for the foreseeable future, our focus for 2012 will be to complete capital projects that retain leases, make existing wells more efficient, or create additional oil production. For 2012, we have budgeted approximately $12.1 million to drill and complete 34 new gas wells in the Basin and five new oil wells in central Oklahoma, and recomplete eight wells in central Oklahoma and 36 wells in the Appalachian Basin. We estimate that for 2012, our average cost for drilling and completing a gas well in the Basin, including the related pipeline infrastructure, will be approximately $149,000. We have also budgeted $ 9.6 million for land, infrastructure and equipment expenditures. We intend to fund our 2012 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 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 2011, we completed 116 gas wells, of which 17 were drilled prior to 2011. Our cost to drill and complete a well, including the related pipeline infrastructure, was approximately $146,000 during 2011. In the second half of the year, we spent a significant amount of time working 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 continue to collect data and to perform studies of this data. We continue to further refine our understanding of the geoscience in the Cherokee Basin to improve individual well results.

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 net daily production of approximately 40 Mcf. Thereafter, production begins a 10-17% exponential decline. The standard economic life is approximately 21 years. Through the use of submersible pumps, we have been able to shorten the initial dewatering period to approximately four months in most of our 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

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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 $45,000 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 longer term, we believe the impact of the multi-seam recompletions and the introduction of submersible pumps results in increased returns. This is due to an increased rate of production, reduced operating costs and an increase in the ultimate per well recoverable reserves. During 2011, 49 recompletions were undertaken. 33 of these recompletions have demonstrated increased production while the remaining 16 still require additional work in order for any production increase to be quantified. At December 31, 2011, we have identified approximately 30 additional wellbores that are candidates for recompletion to multi-seam producers. We are also in the process of reviewing high cost, low production wells to determine if additional zones are capable of production. We expect this process to result in additional wellbores being identified as candidates for recompletion. In addition to the recompletion projects, we have also reviewed many of the initial stimulations of wells throughout the basin and re-stimulation activities have shown to be successful in two of the three wells recently tested.

Our total capital expenditure in the Appalachian Basin in 2011 was $481,000. Our 2012 capital budget discussed above includes 36 recompletions aimed at achieving higher oil production 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.

Cawley, Gillespie & Associates, Inc. (CGA), prepared our reserves estimates at December 31, 2009, 2010 and 2011. 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.

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Estimated Reserves

The following tables present our estimated net proved reserves based on our reserve reports, and the prices used to determine those reserves. 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 for the periods presented were determined using a twelve-month average price.

	2009	2010	2011
Crude oil price per Bbl	$ 61.18	$ 79.43	$ 96.19
Natural gas price per Mmbtu	$ 3.87	$ 4.38	$ 4.12

	Gas (Bcf)	Oil (MMbbl)	Total (Bcfe)	%
December 31, 2009 (a)				
Developed	62.1	0.78	66.8	89%
Undeveloped	7.7	0.05	8.0	11%
Total proved reserves	69.8	0.83	74.8	100%
December 31, 2010 (a)				
Developed	117.0	0.73	121.4	90%
Undeveloped	13.5	0.01	13.5	10%
Total proved reserves (b)	130.5	0.74	134.9	100%
December 31, 2011				
Developed (c)	117.4	1.04	123.7	99%
Undeveloped (d)	0.8	0.03	1.0	1%
Total proved reserves	118.2	1.07	124.7	100%

(a) Does not include any of CEP s reserves as we did not have any ownership interest in CEP during these periods.

(b) The increase in reserves from 2009 to 2010 was due in large part to a decrease in the transportation rate used to estimate the reserves as discussed in Note 21 in Part II, Item 8.

(c) Does not include our proportionate share of proved developed reserves of CEP, comprised of 39.3 Bcf of gas and 0.2 MMbbl of oil. These reserve amounts are based on publicly available data and not subject to our internal controls described above.

(d) Does not include our proportionate share of proved undeveloped reserves of CEP, comprised of 12.4 Bcf of gas and 0.1 MMbbl of oil. These reserve amounts are based on publicly available data and not subject to our internal controls described above.

As disclosed above, we used a price of $4.12/Mmbtu, representing a twelve-month average price, to determine our natural gas reserves at December 31, 2011. Given the recent price decline of natural gas in early 2012, this price results in significantly higher reserves as well as a higher value of reserves than if current prices were used.

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

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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, 2011, we had 1.0 Bcfe of proved undeveloped reserves. During 2011, we developed 3.8 Bcfe of our proved undeveloped reserves reported in 2010 while 0.8 Bcfe was sold in 2011 in connection with the Appalachian Basin asset sale to MHR discussed above. At December 31, 2011, 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 2011 reserve report are scheduled to be developed before 2016.

Production Volumes, Sales Prices and Production Costs

The following table sets forth information regarding our producing 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.

	Year Ended December 31,		
	2009	**2010**	**2011**
Net Production			
Gas (Bcf)	21.2	19.2	18.3
Oil (Bbls)	83,015	76,583	78,087
Gas equivalent (Bcfe)	21.7	19.7	18.8
Oil and Natural Gas Sales ($ in thousands)			
Gas sales	$ 75,106	$ 82,153	$ 72,812
Oil sales	4,787	5,783	7,075
Total oil and natural gas sales	$ 79,893	$ 87,936	$ 79,887
Avg Sales Price (unhedged)			
Gas ($ per Mcf)	$ 3.54	$ 4.27	$ 3.98
Oil ($ per Bbl)	$ 57.66	$ 75.51	$ 90.61
Gas equivalent ($ per Mcfe)	$ 3.68	$ 4.47	$ 4.25
Avg Sales Price (hedged) (1)			
Gas ($ per Mcf)	$ 8.11	$ 5.92	$ 5.84
Oil ($ per Bbl)	$ 69.93	$ 78.63	$ 84.93
Gas equivalent ($ per Mcfe)	$ 8.19	$ 6.09	$ 6.04
Operating expenses ($ per Mcfe)			
Production costs (including gathering costs but excluding production and property taxes)	$ 2.11	$ 1.99	$ 2.09
Production and property taxes	$ 0.47	$ 0.39	$ 0.41
Net Revenue ($ per Mcfe)	$ 1.10	$ 2.08	$ 1.75

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

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	Year Ended December 31, 2009	2010	2011
Realized gain (loss) on hedges			
Gas Hedges	$ 97,130	$ 31,693	$ 34,135
Oil Hedges	1,018	239	(443)
Total	$ 98,148	$ 31,932	$ 33,692

The following tables present our production, average sales prices and production costs, excluding production and property taxes, by area:

	2009		2010		2011	
	MidContinent (1)	Appalachia	MidContinent (1)	Appalachia	MidContinent (1)	Appalachia
Production						
Natural Gas (Bcfe)	20.3	0.9	18.3	0.9	17.7	0.6
Oil (Bbls)	64,583	18,432	64,326	12,257	62,265	15,822
Total production (Bcfe)	20.7	1.0	18.7	1.0	18.1	0.7
Average Sales Prices						
Natural Gas (per Mcfe)	$ 3.31	$ 8.30	$ 4.21	$ 5.57	$ 3.94	$ 5.02
Oil (per bbl)	59.30	51.90	76.27	71.53	91.22	88.17
Total average sales price (per Mcfe)	3.44	8.34	4.38	6.03	4.17	6.34
Production Costs (per Mcfe)	$ 2.05	$ 3.25	$ 1.98	$ 2.30	$ 2.13	$ 1.86

(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, 2009, 2010 and 2011. Our data for 2010 and 2011 includes all wells mechanically capable of production. Our data for 2009 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, 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
December 31, 2011	3,223	3,178.3	62	59.4	3,285	3,237.7

(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, 2009 (2)(3)	446,129	432,008	139,018	130,161	585,147	562,169
December 31, 2010 (4)(5)	436,566	424,778	90,498	86,392	527,064	511,170
December 31, 2011 (6)(5)	442,786	430,687	71,902	69,397	514,688	500,084

(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 37,805 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 at December 31, 2009. There are certain drilling or payment obligations that must be met before this unearned acreage is earned.

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(4) 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.
(5) Includes acreage in the states of Kansas, Oklahoma, West Virginia, and New York.
(6) Includes approximately 29,081 gross and 28,017 net acres attributable to various farm-out agreements or other mechanisms in the Appalachian Basin. Approximately 9,840 net acres are earned and approximately 18,177 net acres are unearned under these agreements at December 31, 2011. There are certain drilling or payment obligations that must be met before this unearned acreage is earned.

At December 31, 2011, we had 347,364 net developed and 117,499 net undeveloped acres in the Cherokee Basin and 8,870 net developed and 24,871 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.

	Years Ended December 31,					
	2009		2010		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled						
Productive						
Dry	1	1				
Development wells drilled						
Productive	4	2.5	163	163	116	116
Dry						
Wells plugged and abandoned	(11)	(11)	(2)	(2)	(1)	(1)
Wells divested			(7)	(7)		
Wells acquired	9	1.6				
Net increase in capable wells	3	(5.9)	154	154	115	115
Recompletion of old wells						
Capable of production			29	29	49	49

In addition to the activity above, in 2011 we drilled but did not complete five wells in the Cherokee Basin and also plugged and abandoned an additional 29 wells. We did not include the 29 plugged and abandoned wells in the table above as those wells were inactive and not capable of producing during the entire duration of our ownership in them.

Gas Gathering

We gather substantially all of our Cherokee Basin production on our own gathering system. In addition, we gather a minor amount of gas produced by others. Throughput on our gathering system in the Cherokee Basin was 23,584 Mmcf and 22,802 Mmcf in 2010 and 2011, respectively.

We receive fees from third parties to gather their gas on our system. Approximately 6% of the gas transported on our Cherokee Basin gathering systems during 2011 was produced by 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 includes 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 11 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

At December 31, 2011, we had approximately 2,993 leases covering approximately 500,084 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 464,863 net acres, of which 68,313 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 38,684 net acres are scheduled to expire before December 31, 2012. 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 18,177 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 2011, approximately 34% of our MidContinent gas production was sold to ONEOK Energy Marketing and Trading Company (ONEOK) and approximately 81% and 16% of our MidContinent oil production was sold to Sunoco Partners Marketing & Terminals L.P. and Coffeyville Refining, respectively. The

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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.

Approximately 87% of our 2011 Appalachian Basin gas production was sold to Dominion Field Services 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 2011 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 2011, approximately 67% of the revenue from the KPC Pipeline was from transportation contracts with KGS. The remaining 33% was from a mix of long-term and 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 2011 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 natural gas prices are not at levels that warrant actively hedging and an appropriate amount of our oil production is hedged. 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

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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.

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, fuel 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,

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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.

Seasonality

Production

In the past, freezing weather and storms in the winter and flooding in the spring and summer have 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. 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 products that limit freezing on wells and compressors and using heavy equipment to facilitate faster access to wells in inclement weather 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 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.*

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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 emission, release and discharge of materials into, and the protection of, the environment and the protection of natural resources and wildlife and imposing liability for 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 limitations on our business. 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.

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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 Natural Gas Act of 1938 (NGA), Natural Gas Policy Act of 1978 (NGPA) and The Energy Policy Act of 2005 (EP Act 2005). FERC regulation affects the price and terms for access to natural gas pipeline 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. 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 which may subject us to fines and additional costs and regulatory burdens that would substantially increase our operating costs and 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.

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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, other than those regulations that prohibit certain practices, such as price manipulation, in the sale of natural gas. 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 (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

At December 31, 2011, we had 233 field employees in offices located in Kansas, Oklahoma, Pennsylvania, and West Virginia, and 68 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 2011, the NYMEX natural gas futures price ranged from a high of $4.85 per Mmbtu to a low of $2.99 per Mmbtu. At March 1, 2012, the NYMEX natural gas futures price was $2.46 per Mmbtu. Approximately 97.5% 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;
- 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 the drilling of wells and the construction of infrastructure to transport the gas produced;

- 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.

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 rendered 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, during 2009 we recognized a ceiling test impairment of $102.9 million related to our oil and gas properties as well as impairment charges of $53.6 million on our interstate pipeline and related contract-based intangible assets and $112.2 million on our gathering system assets. We may incur further impairment charges in the future which could have a material adverse effect on our results of operations.

We have reduced debt but we remain highly leveraged.

At December 31, 2011, we had $213 million of contractual commitments outstanding, consisting of debt service requirements, non-cancelable operating lease and purchase obligation commitments. Of such amount, $190 million was outstanding under our $350 million secured borrowing base revolving credit facility with a current borrowing base of $200 million. There has been a significant decline in natural 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 at April 30, 2012. 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, which we currently expect, 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.

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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 are unable to pass through all of our costs and expenses for gathering and compression to royalty owners under our gas leases, which reduces 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 currently do 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. During 2011, we reached settlements of several royalty owner lawsuits in Oklahoma and Kansas. These lawsuits were related, in part, to the amounts previously deducted by us to cover the costs and expenses for gathering and compression. Please see Part I, Item 3. Legal Proceedings for a discussion of the litigation. As a result of these settlements, we have begun charging post-production costs to royalty and overriding royalty interest owners pursuant to an agreed upon formula. 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.

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.

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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.

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 average prices and expected 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; and

changes in governmental regulations or taxation.

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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 harmful 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 harmful substances. We may drill 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.

Prior to 2009, substantially all of the revenues from the KPC Pipeline were generated under firm capacity transportation contracts with Kansas Gas Service and Missouri Gas Energy. These contracts generated 96% and 91% of total revenues from the KPC Pipeline in 2008 and 2009, respectively. The MGE firm contract expired on

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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 67% in 2011, and provide for volume step downs 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.

CEP s limited liability company agreement may prohibit us from engaging in a business combination or other transaction with CEP until December 2014.

CEP s limited liability company agreement adopts Section 203 of the Delaware General Corporation Law. Section 203 as it applies to CEP prevents an interested unitholder, defined as a person who owns 15% or more of CEP s outstanding common units, from engaging in business combinations with CEP for three years following the time such person becomes an interested unitholder, unless, among other things, the business combination is approved by CEP s board of managers and holders of at least two-thirds of the outstanding voting common units not owned by the interested unitholder. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. This provision of CEP s limited liability company agreement could prohibit us from engaging in a business combination or other transaction with CEP, including transactions that would be beneficial to both our stockholders and CEP s unitholders, until December 2014.

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

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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, fuel 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

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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.

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, at December 31, 2011, we held leases on approximately 464,863 net acres, of which 68,313 net acres are not currently held by production. Unless we establish commercial production on the properties subject to these leases during their term, they will expire. Leases covering approximately 38,684 net acres are scheduled to expire before December 31, 2012. If these leases expire and are not renewed, we will lose the right to develop the related properties.

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 also affects 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 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.

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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. Moreover, on October 24, 2011, the United States Court of Appeals for the Fifth Circuit vacated the posting requirements as applied to non-interstate pipelines and gathering facilities on the grounds that they exceeded FERC s authority under the NGA. We do not know whether FERC will seek rehearing of this decision from the Fifth Circuit or petition for writ of certiorari to the United States Supreme Court, or whether it will otherwise modify its regulations relating to natural gas reporting in the future. 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 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 northern 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 NGA, to prohibit market manipulation. It also amended the NGA and the 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.

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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, which 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 in existence or 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 limitations 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. We may not be able to recover these costs from insurance. 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 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.

In the event (1) water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, (2) our wells produce water in excess of the applicable volumetric permit limits, (3) the disposal wells fail to meet the requirements of all applicable regulatory agencies, or (4) 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 managed or 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 the 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.

On August 25, 2011, the DOT s Pipeline and Hazardous Materials Safety Administration, or PHMSA, published an advanced notice of proposed rulemaking in which the agency is seeking public comment on a

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number of changes to its natural gas transmission pipeline regulations contained in 49 C.F.R. Part 192 including: (1) modifying the definition of high consequence areas; (2) strengthening integrity management requirements as they apply to existing regulated operators and could be applied to currently exempt operators should the exemptions be removed; (3) strengthening or expanding various non-integrity pipeline management standards relating to such matters as valve spacing, automatic or remotely-controlled valves, corrosion protection, and gathering lines; and (4) adding new regulations to govern the safety of underground natural gas storage facilities including underground storage caverns and injection withdrawal wells piping that are not currently regulated under the Part 192 regulations. PHMSA has specifically indicated an intent in this rulemaking to address the need for standards governing the safety of underground natural gas storage facilities. Public comments on these matters were submitted to PHMSA in December 2011, and a final rule from PHMSA is forthcoming.

On January 3, 2012, President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The Act increases the maximum civil penalties for administrative enforcement actions, requires the DOT to study and report on the sufficiency of existing gathering line regulations to ensure safety and the use of leak detection systems by hazardous liquid pipelines, requires pipeline operators to verify their records on maximum allowable operating pressure, and imposes new emergency response and incident notification requirements.

KPC completed all baseline assessments of the covered high consequence area integrity testing in 2009. KPC had no expenditures in 2010 or 2011 to implement pipeline integrity management program testing. KPC also incurred costs of approximately $400,000 in 2009, $30,000 in 2010 and $60,000 in 2011 to complete the last year of a Stray Current Survey resulting from a 2005 DOT audit. A closure letter from PHMSA was received for the survey and related remediation. KPC spent a total of $1.9 million. As part of the KPC Integrity Plan, it will begin its reassessment program of high consequence areas in 2012 with 26 miles of pipeline to be reassessed in the Kansas City area. KPC will be testing two high consequence areas in 2012 as a part of the regulatory seven year cycle. It will also continue to hydrotest the pipeline. The capital budget for these tests in 2012 is $225,000 with an operating expense budget of $450,000. 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.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcement of federal interstate pipeline safety regulations and inspection of interstate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with any state laws and regulations which are determined to be applicable to our operations.

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

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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) with reporting beginning in 2012 for emissions occurring in 2011. 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 in the future.

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 GHG, and modifications of existing major stationary sources that significantly increase their GHG 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 GHG 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 GHG, and more than 20 states, either individually or through multi-state regional initiatives, have already taken legal measures intended to reduce GHG, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs.

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 GHG, pay any taxes related to our GHG and/or administer and manage a GHG 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.

Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. We may incur expenditures in the future for air pollution control equipment in connection with obtaining or maintaining operating permits and approvals for air emissions. For instance, on July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA s proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The proposed rules would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment in addition to leak detection requirements for natural gas processing plants. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by April 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment.

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The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans or limit future development activity in the affected areas.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely employ hydraulic fracturing in our drilling activity. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

State legislatures and agencies are also enacting legislation and promulgating rules to regulate hydraulic fracturing and require disclosure of hydraulic fracturing chemicals. For example, the Oklahoma Corporation Commission is currently considering draft amendments to its regulations that would require operators and service companies to disclose certain hydraulic fracturing chemical information through a national online database, FracFocus.org. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic-fracturing practices. In addition, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. In addition to the EPA, other federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities and Exchange Commission to investigate the natural-gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural-gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural-gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanism.

Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance

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Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically-fractured gas wells. These standards include the reduced emission completion (REC) techniques developed in EPA s Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently researching the effect these proposed rules could have on our business. Final action on the proposed rules is expected no later than April 2012.

Increased regulation and attention given to the hydraulic-fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic-fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

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 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.

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, our business and results of operations could be adversely affected.

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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.

White Deer Energy L.P. and its affiliates (White Deer) beneficially own approximately 71% 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, 2012, including common shares owned and the effect of their outstanding warrants, White Deer beneficially owns 23,746,478 shares, or approximately 71%, 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. The voting power of the Series B Preferred Stock issued with the warrants is limited to 45% of the votes applicable to all outstanding voting stock. In addition, 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 is our controlling stockholder and is 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.

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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, predict, project, or t 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;
- 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.

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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, which is incorporated by reference herein in response to this Item. A substantial portion of our assets are pledged to collateralize our secured credit facilities. See Note 10 in Part II, Item 8. Financial Statements and Supplementary Data.

Administrative Facilities

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

We own four buildings within the vicinity of Chanute, Kansas and one in Lenapah, Oklahoma, for our MidContinent operations.

We lease approximately 1,500 square feet of office space on a month-to-month basis for field personnel in Harrisville, West Virginia.

We have leased facilities in 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 December 31, 2016. The Wichita office consists of approximately 1,240 square feet on an annual lease expiring December 31, 2012. 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 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. 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.

During 2011, we settled various royalty owner lawsuits in Kansas and Oklahoma. The Oklahoma settlements included $5.6 million in cash while the Kansas settlements included $7.5 million in cash. We made payments of $5.6 million for the Oklahoma royalty settlement in July 2011 and $3.0 million for the Kansas royalty settlement in January 2012. We expect to pay the remaining $4.5 million in January 2013.These lawsuits and the related settlements are further discussed in Note 14 in Part II, Item 8. *Financial Statements and Supplementary Data.*

ITEM 4. ***MINE SAFETY DISCLOSURES***
Not applicable.

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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
2010		
March 31 (1)	$ 22.98	$ 8.12
June 30	$ 11.02	$ 4.51
September 30	$ 5.89	$ 2.75
December 31	$ 5.20	$ 3.29
2011		
March 31	$ 7.44	$ 3.76
June 30	$ 8.45	$ 5.15
September 30	$ 6.73	$ 3.05
December 31	$ 4.60	$ 2.22

(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, 2012 was $3.78 per share. At March 1, 2012, there were 12,115,570 shares of common stock outstanding held of record by approximately 287 stockholders. Warrants to purchase 21,566,245 shares of our common stock at a weighted average exercise price of $3.23 per share were outstanding and held by White Deer. Warrants to purchase 673,822 shares of our common stock at a weighted average exercise price of $7.07 per share were outstanding and held by CEG.

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.

Issuer Purchases of Equity Securities

None.

ITEM 6. *SELECTED FINANCIAL DATA*

We have derived the following selected consolidated financial information for PostRock at and for the period ended December 31, 2010, and the year ended December 31, 2011, and for our Predecessor for the period from January 1 to March 5, 2010, and for the year ended December 31, 2009 from the audited consolidated financial statements of PostRock included in Part II, Item 8. *Financial Statements and Supplementary Data.* We have derived the selected consolidated financial information of our Predecessor at December 31, 2008 and 2009 and for the years ended December 31, 2007 and 2008 from the Predecessor s audited consolidated financial information included in its SEC filings.

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	Predecessor Years Ended December 31, 2007	2008	2009	January 1 to March 5, 2010	March 6 to December 31, 2010	Year Ended December 31, 2011
Statement of Operations Data						
Revenues						
Oil and gas sales	$ 105,285	$ 162,499	$ 79,893	$ 18,659	$ 69,277	$ 79,887
Gathering	6,667	8,704	7,760	1,076	4,771	5,239
Pipeline	3,186	19,472	18,428	1,749	8,380	11,183
Total	115,138	190,675	106,081	21,484	82,428	96,309
Costs and expenses						
Production expense	56,299	66,218	55,961	8,645	38,329	47,136
Pipeline expense	1,094	7,635	6,573	1,110	5,195	5,219
General and administrative	21,023	28,269	40,693	5,735	19,065	17,199
Litigation reserve			1,030		1,640	11,592
Depreciation, depletion and amortization	39,782	70,445	47,802	4,164	18,683	27,662
(Gain) loss on disposal of assets	322	(24)	25		(13,495)	(10,560)
Impairments		298,861	268,630			
Loss (recovery) of misappropriated funds	2,000		(3,412)		(1,592)	
Total	120,520	471,404	417,302	19,654	67,825	98,248
Operating income (loss)	(5,382)	(280,729)	(311,221)	1,830	14,603	(1,939)
Other income (expense)						
Gain from derivative financial instruments	1,961	66,145	48,122	25,246	47,870	35,429
Loss from equity investment						(4,607)
Gain on forgiveness of debt					2,909	1,647
Other income (expense), net	(9)	305	108	(4)	(24)	207
Interest expense, net	(43,628)	(25,373)	(29,329)	(5,336)	(20,137)	(10,707)
Total	(41,676)	41,077	18,901	19,906	30,618	21,969
Income (loss) before income taxes	(47,058)	(239,652)	(292,320)	21,736	45,221	20,030
Income taxes						
Net income (loss)	(47,058)	(239,652)	(292,320)	21,736	45,221	20,030
Net (income) loss attributable to noncontrolling interest	2,904	72,268	147,398	(9,958)		
Net income (loss) attributable to controlling interest	(44,154)	(167,384)	(144,922)	11,778	45,221	20,030
Preferred dividends					(1,980)	(7,779)
Accretion of redeemable preferred stock					(327)	(1,580)
Net income (loss) available to common stock	$ (44,154)	$ (167,384)	$ (144,922)	$ 11,778	$ 42,914	$ 10,671
Net income (loss) per common share						
Basic	$ (1.97)	$ (6.20)	$ (4.55)	$ 0.37	$ 5.29	$ 1.21
Diluted	$ (1.97)	$ (6.20)	$ (4.55)	$ 0.36	$ 4.62	$ 0.71
Balance Sheet Data (at end of period)						
Total assets	$ 672,537	$ 650,176	$ 283,655	$ 310,234	$ 296,812	$ 306,711
Noncurrent liabilities excluding debt	$ 9,249	$ 10,152	$ 15,121	$ 17,148	$ 13,831	$ 20,903
Long-term debt	$ 233,046	$ 343,094	$ 19,295	$ 20,251	$ 209,721	$ 190,000
Redeemable preferred stock	$	$	$	$	$ 50,622	$ 56,736

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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 from 2009 to 2011 due to various liquidity and corporate management related matters, (3) the acquisition of the KPC Pipeline on November 1, 2007, (4) the PetroEdge acquisition in July 2008, (5) our investment in CEP during 2011, (6) investigation and litigation costs associated with the misappropriation in 2008 and 2009, (7) the Recombination in 2010 and expenses related to the Recombination in 2009 and 2010, (8) 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, and (9) the sale of most of our Appalachian Basin oil and gas properties in 2010 and 2011.

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

The accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be read in conjunction with the following discussion.

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 and gas 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 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.

Strategy

Our focus, particularly in the current challenging pricing environment, is on efficiently growing reserves, lowering costs and strengthening our balance sheet. We seek to achieve predictable, long-term production with low costs through effective drilling programs and modern completion techniques, efficient management of our field operations and leveraging our existing resources in the Cherokee Basin. 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. When appropriate, we intend to pursue opportunistic acquisitions that are accretive to our existing operations. With the current disparity between oil and natural gas prices, in the near term, we are seeking to extract further returns from our oil producing assets through development projects and selective hedging.

Although we are evaluating strategic alternatives related to our KPC Pipeline, we are also working to increase the amount of gas being transported on the pipeline, creating capacity constraints that we believe will lead to long-term firm transportation agreements.

Financial and Operating Results

During 2011, the U.S. and other economies continued the modest growth which started during 2010. Although year-over-year crude oil prices showed improvement from increased demand, an oversupply of natural gas drove our realized natural gas price down significantly. A combination of this reduction of natural gas prices and lower production volumes due to our reduced development activity beginning in 2009 and continuing through 2011 resulted in lower oil and gas revenue. While our capital spending program was down slightly from the 2010 level, we acquired a 26.4% interest in CEP, completed the sale of certain of our Appalachian Basin producing assets, resolved all of the remaining legacy litigation of our predecessors and continued to strengthen our balance sheet.

Significant financial and operating highlights during 2011 included the following:

- Recorded proved reserves of nearly 124.7 Bcfe at December 31, 2011. Although we did not acquire significant additional properties, through a series of geologic and engineering studies we now have a better understanding of our existing reserves.

- Completed 116 new gas wells and recompleted 49 gas wells.

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- Began implementation of a field optimization program in the second quarter of 2011.
  - Rationalization of rolling stock, one of the first steps of the program, reduced vehicle and equipment costs by $332,000, or 13.0%, from 2010 levels.
  - Rationalization of compressors, also one of the first steps, reduced compression costs by $600,000, or 5.4%, from 2010 levels.
  - Additional steps made in the first quarter of 2012 are expected to reduce costs by another $2.0 million a year going forward.
- Reduced general and administrative expenses by $7.6 million, or 30.6%.
- Reduced debt by $27.2 million.
- Closed on the second and third phases of our Appalachian Basin asset sale for an aggregate of $16.6 million.
- Acquired a 26.4% voting interest in CEP in two separate transactions for $17.6 million collectively.
- Settled all of our Oklahoma and Kansas royalty interest owner lawsuits for a combined $13.1 million, of which $5.6 million was paid in July 2011, $3.0 million was paid in January 2012 and $4.5 million will be paid by January 2013.

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 gas sales volumes; (5) firm transportation contracted volumes; and (6) 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 $4.00 per Mmbtu in 2011. NYMEX strip prices at February 8, 2012, average $2.999/Mmbtu, $3.366/Mmbtu, and $3.612/Mmbtu, for the forward 12, 24 and 36 month periods. 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 2011, the basis differential in the Cherokee Basin ranged from a discount of $0.24/Mmbtu to a premium of $0.23/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 2.7 percent in 2011, and forecasts an increase of 1.3 billion cubic feet per day (Bcf/d), or 2.0%, in 2012. This increase is driven by growth in all sectors with the largest volume increase in the electric power sector. Total natural gas consumption is expected to

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grow by 1.3 percent in 2013 to 69.14 Bcf/d. Total marketed natural gas production increased by the largest year-over-year volumetric amount in history in 2011, an estimated 4.5 Bcf/d, or 7.4 percent, due in large part to increases in shale gas production. Although low spot and future prices are expected to continue, EIA projects average total production to grow by 2.2 percent in 2012 and 1.0 percent in 2013. These projected increases are driven by high initial production rates from new wells, associated natural gas production from oil drilling and a backlog of uncompleted of unconnected wells going into 2012. 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. Increased consumption can only partially offset the effect of record-high natural gas inventories caused by the continued growth in natural gas production and a warm winter. EIA is expecting these factors to lead to decreased gas prices in 2012 increasing slightly in 2013.

EIA expects the recent tightening of world oil markets to moderate in 2012 and resume in 2013. World oil consumption is expected to grow by an annual average of 1.3 million Bbls/d in 2012 and 1.5 million Bbls/d in 2013 while the growth in supply from non-Organization of the Petroleum Exporting Countries (non-OPEC) countries is expected to increase by 0.9 million Bbls/d in 2012 and 0.8 million Bbls/d in 2013. 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 a significant oil supply disruption occur, OPEC members not increase production, or projected non-OPEC projects come online more slowly than expected, oil prices could be significantly higher. 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 $100 per barrel in 2012 and continue to rise, reaching $106 per barrel by the end of 2013.

Drilling Programs

We initially budgeted $43.6 million for drilling and development in 2011. Our actual expenditures for the year totaled $23.8 million, for which we drilled and connected 99 development wells, completed 17 new wells drilled in prior years and recompleted 49 wells. Our lower spending levels relative to budgeted figures from the beginning of 2011 were a reflection of depressed gas prices and the clear need to better understand the results of our drilling activity.

In order to understand how to improve our wells performance, we have been conducting and continue to conduct 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. The studies have enabled us to better understand our production curves and production areas. We are also evaluating the possibility of finding conventional oil and gas reserves in other geologic horizons.

With the significant reduction in natural gas prices at the end of 2011, continuing into 2012 and expected for the foreseeable future, our focus for 2012 will be to complete capital projects that retain leases, make existing wells more efficient, or create additional oil production. For 2012, we have budgeted approximately $12.1 million to drill and complete 34 new gas wells in the Basin and five new oil wells in central Oklahoma, and recomplete eight wells in central Oklahoma and 36 wells in the Appalachian Basin. We intend to fund our 2012 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.*

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Results of Operations

	2009	2010	2011
		(In thousands)	
Revenues			
Oil and gas sales	$ 79,893	$ 87,936	$ 79,887
Gathering	7,760	5,847	5,239
Total production segment	87,653	93,783	85,126
Pipeline segment	18,428	10,129	11,183
Total	$ 106,081	$ 103,912	$ 96,309
Operating profit (loss)			
Production(1)	$ (222,839)	$ 40,972	$ 24,459
Pipelines(2)	(50,071)	309	2,393
Total segment operating profit (loss)	(272,910)	41,281	26,852
General and administrative expenses	(40,693)	(24,800)	(17,199)
Recovery of misappropriation funds	3,412	1,592	
Litigation reserve	(1,030)	(1,640)	(11,592)
Total operating profit (loss)	$ (311,221)	$ 16,433	$ (1,939)

(1) Includes impairment of production properties of $215.1 million in 2009, which includes the impairment of our gathering system of $112.2 million.

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

Year ended December 31, 2010 compared to the year ended December 31, 2011

The following table presents financial and operating data for our production and pipeline segments for the fiscal years ended December 31, 2010 and 2011.

	Year Ended December 31,		Increase/	
	2010	2011	(Decrease)	
	($ in thousands except per unit data)			
Production Segment				
Oil and gas sales	$ 87,936	$ 79,887	$ (8,049)	(9.2)%
Gathering revenue	$ 5,847	$ 5,239	$ (608)	(10.4)%
Production expense	$ 46,974	$ 47,136	$ 162	0.3 %
Depreciation, depletion and amortization	$ 19,409	$ 24,088	$ 4,679	24.1 %
Gain (loss) on disposal of assets	$ 13,572	$ 10,557	$ (3,015)	(22.2)%
Production Data				
Total production (Mmcfe)	19,685	18,778	(907)	(4.6)%
Average daily production (Mmcfe/d)	53.9	51.4	(2.5)	(4.6)%
Average Sales Price per Unit (Mcfe)				
Natural Gas (Mcf)	$ 4.27	$ 3.98	$ (0.29)	(6.8)%
Oil (Bbl)	$ 75.51	$ 90.61	$ 15.10	20.0 %
Natural Gas Equivalent (Mcfe)	$ 4.47	$ 4.25	$ (0.22)	(4.9)%
Average Unit Costs per Mcfe				

Production expense	$ 2.39	$ 2.51	$ 0.12	5.0 %
Depreciation, depletion and amortization	$ 0.99	$ 1.28	$ 0.29	29.3 %
Pipeline Segment				
Pipeline revenue	$ 10,129	$ 11,183	$ 1,054	10.4 %
Pipeline expense	$ 6,305	$ 5,219	$ (1,086)	(17.2)%
Depreciation and amortization expense	$ 3,438	$ 3,574	$ 136	4.0 %
Gain (loss) on disposal of assets	$ (77)	$ 3	$ 80	* %

* Not meaningful

Oil and gas sales decreased $8.0 million, or 9.2%, from $87.9 million for the year ended December 31, 2010, to $79.9 million for the year ended December 31, 2011. This decrease was equally due to reduced production volumes and lower average realized natural gas prices. Cherokee Basin production decreased 569 Mmcfe due to lower than planned development activity and natural production declines while Appalachian Basin production decreased 330 Mmcfe from the prior year primarily due to the divesture of the Appalachian Basin properties. Average realized natural gas prices decreased from $4.47 per Mcfe in 2010 to $4.25 per Mcfe in 2011. Oil and gas sales exclude hedge settlements.

Gathering revenue decreased $608,000, or 10.4%, from $5.8 million during the year ended December 31, 2010, to $5.2 million during the year ended December 31, 2011. The decrease was primarily the result of decreased third-party volumes transported and lower natural gas prices. The majority of our third-party gathering revenue is priced based on a percentage of gas volumes. With lower prices, other producers produced less and the gas we retained was at a lower rate per Mcfe. The effects of the Oklahoma and Kansas royalty settlements also reduced gathering revenue during the fourth quarter and will continue to reduce gathering revenue in the future.

Pipeline revenue increased $1.1 million, or 10.4%, from $10.1 million during the year ended December 31, 2010, to $11.2 million during the year ended December 31, 2011. The increase was primarily due to higher revenues from firm transportation contracts as well as higher commodity revenue due to an increase in throughput.

Production expense consists of lease operating expenses, severance and ad valorem taxes and gathering expense. Production expense increased $162,000, or 0.3%, from $47.0 million during the year ended December 31, 2010, to $47.1 million during the year ended December 31, 2011. The slight increase was due to increased labor, workover and repair and electricity costs of $2.4 million partially offset by lower compression, vehicle and equipment, production and ad valorem taxes of $2.2 million. Production expense per Mcfe increased $0.12, or 5.0%, roughly the amount of the production decrease, from $2.39 per Mcfe during the year ended December 31, 2010, to $2.51 per Mcfe during the year ended December 31, 2011.

Pipeline expense decreased $1.1 million, or 17.2%, from $6.3 million during the year ended December 31, 2010, to $5.2 million during the year ended December 31, 2011. The decrease was due to our December 2010 partial termination of a capacity lease and the lease s subsequent expiration in October 2011, partially offset by the costs of gas lost during an external leak in the first quarter of 2011.

Depreciation, depletion and amortization in our production segment increased approximately $4.7 million, or 24.1%, from $19.4 million during the year ended December 31, 2010, to $24.1 million during the year ended December 31, 2011. On a per unit basis, we had an increase of $0.29 per Mcfe from $0.99 per Mcfe during the year ended December 31, 2010, to $1.28 per Mcfe during the year ended December 31, 2011. The increase was primarily due to the reclassification of our gathering system from our pipeline segment to our production segment during the fourth quarter of 2010. This resulted in the gathering system being depleted under a higher rate.

Depreciation and amortization expense in our pipeline segment increased $136,000, or 4.0%, from $3.4 million during the year ended December 31, 2010, to $3.5 million during the year ended December 31, 2011.

Gain from the disposal of production segment assets decreased $3.0 million or 22.2%, from $13.6 million during the year ended December 31, 2010, to $10.6 million during the year ended December 31, 2011. The gain in 2010 was primarily related to the first phase of the Appalachian Basin asset sale while the gain in 2011 was primarily related to the second and third phases of that sale partially offset by $1.9 million of losses on the disposal of excess equipment.

General and administrative expenses decreased $7.6 million, or 30.6%, from $24.8 million during the year ended December 31, 2010, to $17.2 million during the year ended December 31, 2011. As a result of our Recombination and refinancing activities in 2010, we have been able to eliminate significant consulting and other outside service costs associated with those transactions.

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Litigation reserve increased $10.0 million, from $1.6 million during the year ended December 31, 2010, to $11.6 million for the year ended December 31, 2011. The expense in 2010 was primarily related to our securities lawsuits. The expense during 2011 is due to settlement costs for our royalty owner lawsuits in Oklahoma and Kansas. The royalty owner lawsuits included allegations that we failed to properly make payments to certain royalty owners in the past. Our Oklahoma royalty owner lawsuits were settled and funded in July 2011 for $5.6 million. Our Kansas royalty owner lawsuits were settled for $7.5 million; the first payment of $3.0 million was made in January 2012, and an additional $4.5 million payment will be made by January 31, 2013. As part of these settlements, all ambiguity in the calculation of prospective as well as prior royalties in our lease agreements will be eliminated. Going forward, we will charge post-production costs to royalty and overriding royalty interest owners pursuant to an agreed upon formula derived as part of the settlements. These settlements comprise the last material litigation or dispute related to our predecessor entities or management. The expense recorded in 2011 for these lawsuits established the $5.6 million reserve for the Oklahoma matters and increased the reserve for the Kansas lawsuit by $6.0 million.

Recovery of misappropriated funds was $1.6 million for the year ended December 31, 2010. The amount represents recovery of a portion of the funds misappropriated between 2005 and 2007 by former officers. No additional amounts were recovered in 2011.

Gain from derivative financial instruments decreased $37.7 million, or 51.5%, from a gain of $73.1 million during the year ended December 31, 2010, to a gain of $35.4 million during the year ended December 31, 2011. 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. We recorded a $1.7 million unrealized gain and a $33.7 million realized gain on our derivative contracts for the year ended December 31, 2011.

Interest expense, net, decreased $14.8 million, or 58.0%, from $25.5 million during the year ended December 31, 2010, to $10.7 million during the year ended December 31, 2011. The decrease is primarily due to the September 2010 refinancing, which resulted in a lower balance of debt, lower interest rates and decreased amortization of debt issuance costs. Amortization of debt issuance costs, which is a component of interest expense, was $6.1 million lower in 2011 compared to 2010.

Gain on forgiveness of debt decreased $1.3 million, or 43.4%, from $2.9 million during the year ended December 31, 2010, to $1.6 million during the year ended December 31, 2011. Both gains are the result of our debt restructuring, discussed below, in connection with the QER Loan.

Loss from equity investment was $4.6 million during the year ended December 31, 2011. The loss is a result of a decline in the market price of CEP s publicly traded equity, which consequently reduced the value of our investment.

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

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

	Year Ended December 31, 2009	Year Ended December 31, 2010	Increase/ (Decrease)	
	($ in thousands except per unit data)			
Production Segment				
Oil and gas sales	$ 79,893	$ 87,936	$ 8,043	10.1 %
Gathering revenue	$ 7,760	$ 5,847	$ (1,913)	(24.7)%
Production expense	$ 55,961	$ 46,974	$ (8,987)	(16.1)%
Depreciation, depletion and amortization	$ 39,438	$ 19,409	$ (20,029)	(50.8)%
Gain (loss) on disposal of assets	$ (25)	$ 13,572	$ 13,597	* %
Impairment	$ 215,068	$	$ (215,068)	* %
Production Data				
Total production (Mmcfe)	21,733	19,685	(2,048)	(9.4)%
Average daily production (Mmcfe/d)	59.5	53.9	(5.6)	(9.4)%
Average Sales Price per Unit (Mcfe)				
Natural Gas (Mcf)	$ 3.54	$ 4.27	$ 0.73	20.6 %
Oil (Bbl)	$ 57.66	$ 75.51	$ 17.85	31.0 %
Natural Gas Equivalent (Mcfe)	$ 3.68	$ 4.47	$ 0.79	21.5 %
Average Unit Costs per Mcfe				
Production expense	$ 2.58	$ 2.39	$ (0.19)	(7.4)%
Depreciation, depletion and amortization	$ 1.81	$ 0.99	$ (0.82)	(45.3)%
Pipeline Segment				
Pipeline revenue	$ 18,428	$ 10,129	$ (8,299)	(45.0)%
Pipeline expense	$ 6,573	$ 6,305	$ (268)	(4.1)%
Depreciation and amortization expense	$ 8,364	$ 3,438	$ (4,926)	(58.9)%
Gain (loss) on disposal of assets	$	$ (77)	$ (77)	* %
Impairment	$ 53,562	$	*	* %

* Not meaningful

Oil and gas sales increased $8.0 million, or 10.1%, from $79.9 million for the year ended December 31, 2009 to $87.9 million for the year ended December 31, 2010. 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.

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

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

Production expense decreased $9.0 million, or 16.1%, from $56.0 million during the year ended December 31, 2009, to $47.0 million during the year ended December 31, 2010. 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 $575,000. 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.

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Gathering expense was lower primarily due to lower compression costs. Production expense per Mcfe decreased $0.19, or 7.4%, from $2.58 per Mcfe during the year ended December 31, 2009, to $2.39 per Mcfe during the year ended December 31, 2010.

Pipeline expense was generally flat, decreasing $268,000, or 4.1%, from $6.6 million during the year ended December 31, 2009, to $6.3 million during the year ended December 31, 2010.

Depreciation, depletion and amortization in our production segment decreased approximately $20.1 million, or 50.8%, from $39.5 million during the year ended December 31, 2009, to $19.4 million during the year ended December 31, 2010. On a per unit basis, we had a decrease of $0.82 per Mcfe from $1.81 per Mcfe during the year ended December 31, 2009, to $0.99 per Mcfe during the year ended December 31, 2010. 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.

Depreciation and amortization expense in our pipeline segment decreased $4.9 million, or 58.9%, from $8.4 million during the year ended December 31, 2009, to $3.5 million during the year ended December 31, 2010. 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.

Gain from the disposal of production segment assets of $13.5 million during the year ended December 31, 2010, was primarily related to the first phase of the Appalachian Basin asset sale in December 2010.

Impairment of our production properties of $215.1 million for 2009 was recorded, 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 our pipeline assets and related contract intangibles was $53.6 million in 2009 while 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 decreased $15.9 million, or 39.1%, from $40.7 million during the year ended December 31, 2009, to $24.8 million during the year ended December 31, 2010. 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.

Litigation reserve increased $610,000, from $1.0 million for the year ended December 31, 2009, to $1.6 million for the year ended December 31, 2010. The expense in 2010 was primarily related to our federal securities lawsuits while the expense in 2009 was primarily for the initial estimate to resolve our Kansas royalty owner lawsuits. As discussed previously, we reached an agreement to settle our Kansas royalty lawsuits in December 2011.

Recovery of misappropriated funds was $3.4 million during the year ended December 31, 2009, compared to $1.6 million during the year ended December 31, 2010. These amounts represent recoveries of funds misappropriated between 2005 and 2007 by former officers.

Gain from derivative financial instruments increased $25.0 million from $48.1 million during the year ended December 31, 2009, to a gain of $73.1 million during the year ended December 31, 2010. We recorded a

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$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 $41.2 million unrealized gain and a $31.9 million realized gain for the year ended December 31, 2010. 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.

Interest expense, net, decreased $3.9 million, or 13.1%, from $29.4 million during the year ended December 31, 2009, to $ 25.5 million during the year ended December 31, 2010. The decrease was primarily due to the continuing positive effect on underlying rates as a result of our September 2010 refinancing, repayments of debt and lower interest rates on our restructured credit facilities.

Gain on forgiveness of debt was $2.9 million for the year ended December 31, 2010; the gain was recorded in connection with the restructuring of our QER Loan discussed below.

Liquidity and Capital Resources

Debt Reduction

We have reduced our overall debt outstanding from $220.2 million at December 31, 2010 to $193.0 million at December 31, 2011, or 12%. Our debt reduction was achieved primarily through the settlement of our QER Loan utilizing proceeds from the Appalachian Basin asset sale and the retirement of our Secured Pipeline Loan.

Historical Cash Flows and Liquidity

Cash flows from operating activities have historically been driven by the quantities of our production, 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 of 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 $74.6 million, $38.8 million and $42.7 million for the years ended December 31, 2009, 2010 and 2011, respectively. The increase from 2010 to 2011 is primarily due to lower interest charges and general and administrative expenses compared to the prior year coupled with higher realized gains on derivative contracts. These increases more than offset a decrease in cash flow due to the decline in oil and gas revenues in 2011. The decrease from 2009 to 2010 is attributable primarily to a decrease in realized gains on our derivatives offset by changes in working capital. The decrease in realized derivative gain was the result of a one-time gain of $26 million in 2009 when we re-priced certain contracts in order to pay down debt.

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Cash flows from investing activities have historically been driven by exploration and development costs, leasehold acquisitions, acquisitions of businesses and sales of oil and gas properties. Net cash from investing activities was $313,000 for the year ended December 31, 2009, compared to cash used of $13.4 million and $27.8 million for the years ended December 31, 2010 and 2011, respectively. Cash used in investing activities in 2011 was a result of $29.3 million of capital expenditures and $12.9 million of cash for our investment in CEP partially offset by proceeds of $14.4 million (including proceeds of $1.6 million from the sale of stock received as consideration) from asset sales primarily related to the Appalachian Basin sale. Cash used in investing activities in 2010 primarily consisted of capital expenditures of $28.1 million offset in part 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 as we had significantly pared down our acquisition and development related capital expenditures in response to liquidity constraints in 2009. The following table sets forth our capital expenditures, including costs we have incurred but not paid for the periods presented.

	Year Ended December 31,		
	2009	2010	2011
		(In thousands)	
Capital expenditures			
Leasehold acquisition	$ 1,998	$ 2,192	$ 853
Exploration	128		
Development	6,244	27,396	23,825
Pipeline	678	1,362	839
Other items	511	1,370	4,736
Total capital expenditures	$ 9,559	$ 32,320	$ 30,253

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 $67.8 million, $45.5 million and $15.3 million for the years ended December 31, 2009, 2010 and 2011, respectively. The cash used in 2011 was primarily due to $15.3 million in net repayments of debt. The cash used in 2010 was primarily due to $99.1 million in net repayments of debt and $6.5 million of debt and equity financing costs offset in part by $60.0 million of proceeds from the issuance of preferred securities and warrants to White Deer. The cash used in financing activities in 2009 was primarily due to net repayments of debt of $63.1 million and $4.7 million in debt amendment fees.

CEP Investment

During 2011, we acquired a 26.4% voting interest in CEP in two separate transactions at a total cost of $17.6 million. In the first transaction that closed in August 2011, we acquired a 14.9% voting interest in CEP which included the right to appoint two directors to CEP s Board. The 14.9% voting interest consisted of 485,065 of CEP s outstanding Class A Member Interests, representing all of the class, and 3,128,670 Class B Member Interests. In the second transaction that closed in December 2011, we acquired an additional 2,790,224 Class B Member Interests, bringing our ownership to a combined 26.4% voting interest at December 31, 2011. The $17.6 million total cost included $12.6 million of cash, 1,000,000 shares of our common stock with a fair value of $4.1 million, warrants to acquire an additional 673,822 shares of our common stock with a fair value of $518,000, and acquisition costs of $352,000. Of the warrants, 224,607 are exercisable for one year following issuance at an exercise price of $6.57 a share, 224,607 are exercisable for two years following issuance at $7.07 a share and 224,608 for three years following issuance at $7.57 a share.

In June 2011, we agreed to purchase CEG s roughly 26.4% interest in CEP. Closing was contingent on the approval of CEP s Board of Managers. After CEP s Board declined to consider the request, we terminated the agreement, purchasing approximately a 14.9% interest in CEP in August 2011. The less than 15% stake avoided triggering certain anti-takeover provisions of the Delaware statutes. When CEG decided to sell the remainder of their position in December 2011, we elected to purchase it despite the Delaware statute. The purchase increased our ownership position to approximately 26.4%. Under the Delaware statute, a business combination or other corporate transaction with CEP may now not be possible prior to December 2014. Despite their prior lack of support, we continue to hope the Board and management of CEP will work with us to explore opportunities for increased efficiency in the Cherokee Basin. The importance of efficiency has obviously increased dramatically as gas prices languish below $3.00/Mcf in early 2012. Unfortunately, while CEP s Board has indicated a willingness to discuss these matters, they have insisted that the substance and even the existence of any such discussion remain secret. To date, we have been unwilling to keep the overall status of any discussions from our shareholders.

We believe that our 26.4% voting interest in CEP at December 31, 2011, along with the right to appoint two directors to CEP s Board provide us the ability to exercise significant influence over the operating and financial policies of CEP. Rather than accounting for the investment under the equity method, we have elected the fair value option to account for our interest in CEP and recognize the change in fair value in our results of operations.

The Class B Member Interests are traded on the New York Stock Exchange under the ticker symbol CEP with a closing price of $1.96 per unit at December 30, 2011.

CEP is focused on the acquisition, development and production of oil and natural gas properties as well as related midstream assets. All of its proved reserves are located in the Cherokee Basin in Kansas and Oklahoma, the Black Warrior Basin in Alabama, the Woodford Shale in the Arkoma Basin in Oklahoma and the Central Kansas Uplift in Kansas and Nebraska. Because PostRock and CEP each have the majority of their assets in the Cherokee Basin of Kansas and Oklahoma, the investment was made in an attempt to work with CEP to explore opportunities to reduce costs and enhance value for the companies respective investors.

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 7 1/2 year warrants to purchase 19,047,619 shares of our common stock at an exercise price of $3.15 per share. 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 have not paid cash dividends since White Deer s initial investment but instead have chosen to increase the liquidation preference on the Series A Preferred Stock by $9.8 million, the cumulative amount of accrued dividends through December 31, 2011. Additional warrants to purchase 2,518,626 shares of our common stock at a weighted average exercise price of $3.87 were also issued since the initial investment. 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, 2011, the Series A Preferred Stock had a liquidation preference of $69.8 million, and there were outstanding warrants to purchase a total of 21,566,245 shares of common stock at a weighted average exercise price of $3.23.

On February 9, 2012, we issued an additional 2,180,233 shares of common stock to White Deer for an aggregate purchase price of $7.5 million, or $3.44 per share.

Credit Agreements

We had the following credit agreements at December 31, 2011:

(i) Borrowing Base Facility

A $350 million secured borrowing base revolving credit facility with a current borrowing base of $200 million and outstanding borrowings of $190 million at December 31, 2011, 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.

(ii) Secured Pipeline Loan

A term loan with a balance of $3.0 million at December 31, 2011, secured by, among other things, a first lien on our interstate natural gas transportation pipeline and a second lien on our Cherokee Basin exploration and production assets, certain producing Appalachian production assets and the Cherokee Basin gas gathering system. This loan was entirely repaid in February 2012.

See Note 10 in Part II, Item 8. in this Annual Report on Form 10-K for a summary of the material terms of these credit facilities.

Settlement of QER Loan

In December 2010, we entered into an agreement with MHR to sell certain oil and gas properties and related assets in West Virginia. The sale closed in three phases for a total of $44.6 million. The first phase closed in December 2010 for $28 million while the next two phases closed in January and June 2011 for a combined $16.6 million. The amount received for the first and second phases was paid half in cash and half in MHR common stock, while the amount received for the third phase was paid entirely in cash. The sale enabled us to reduce debt and focus on the Cherokee Basin. We recorded gains of $13.7 million during 2010 and $12.5 million during 2011 related to the three phases of the asset sale.

Included in the $44.6 million aggregate purchase price paid by MHR was approximately $41.6 million representing the purchase price of assets owned by one of our subsidiaries, PostRock Eastern Production, LLC, formerly named Quest Eastern Resource LLC (QER), pledged as collateral under the QER Loan. From the sale proceeds, we made payments to the lender, Royal Bank of Canada (RBC), in the amount of $21.2 million in December 2010, $9.3 million in January 2011 and $4.3 million in June 2011. Concurrent with the June 2011 payment and pursuant to the terms of an asset sale agreement with RBC, we fully settled the outstanding balance of the QER Loan of approximately $843,000 by issuing 141,186 shares of our common stock with a fair value of $744,000 to RBC. We expect to recover the full amount of the $843,000 payment to RBC through the release of escrowed proceeds from the Appalachian Basin asset sale in June 2012.

In connection with the sale, $6.4 million was set aside in escrow to cover potential claims for indemnity and title defects. The total first and second closing escrowed amount of $5.9 million is to be released in June 2012 while the third closing escrowed amount of $564,000 is to be released in December 2012. If all of the amounts in escrow are released, we would receive a total of $1.5 million, which includes $843,000 in connection with the QER Loan discussed above. The remaining amount would be released to RBC and a third-party.

The settlement of the QER Loan was facilitated by the restructuring of a prior loan that met the criteria under accounting guidance to be classified as a troubled debt restructuring. We had previously recorded a gain on debt restructuring related to the QER Loan of $2.9 million in 2010. Following a re-evaluation of the maximum sum of future cash flows that would be paid to RBC, we recorded an additional gain of $1.6 million during the second quarter of 2011. The gain includes $799,000 of accrued interest that was forgiven at the time the balance of the loan was settled.

Sources of Liquidity in 2012 and Capital Requirements

We rely on our cash flows from operating activities as a source of internally generated liquidity. During the past three 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 our ability to control operating expenses. We generated cash of $31.9 million and

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$33.7 million from settlements of our oil and gas derivatives during 2010 and 2011, respectively. During this time, our derivative contracts covered approximately 83% and 74% of our production in 2010 and 2011. The volume covered by outstanding contracts as a percentage of our current year production is 60% in 2012 and 50% in 2013. At this time, we believe that natural gas prices are not at levels that warrant actively hedging. When prices improve, we intend to resume our natural gas hedging activity. To a lesser extent, we also rely on the sale of our non-core production assets to internally generate liquidity. As discussed above, the sale of our Appalachian Basin assets generated $28.0 million, $11.7 million and $4.9 million in proceeds in December 2010, January 2011 and June 2011, respectively.

We rely on our borrowing base credit facility as an external source of long and short-term liquidity. At March 1, 2012, with $182.0 million of outstanding borrowings and $1.6 million in letters of credit, we have $16.4 million of availability under this facility. The borrowing base under our borrowing base credit facility was redetermined effective July 31, 2011, based on reserves at March 31, 2011. The borrowing base under that facility is determined based on the value of our oil and natural gas reserves at our lenders forward price forecasts, which are generally derived from futures prices. As a result of a decline in lender forward price forecasts and the roll-off of hedges, our borrowing base was reduced from $225 million to $200 million. Due to further declines in gas prices since our July 31, 2011, redetermination, our next borrowing base redetermination, which is based on reserves at December 31, 2011, and effective as of April 30, 2012, is expected to result in a further decrease in our borrowing base below our outstanding borrowings at March 1, 2012. 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. We believe we will be able to fund any repayment primarily with cash flow from operations, and we have other potential sources of liquidity, including sale of non-core assets and monetization of our hedges.

We have an effective $100 million universal shelf registration statement on Form S-3. We are initially limited to selling debt or equity securities under the shelf registration statement in one or more offerings over a 12 consecutive month period for a total initial public offering price not exceeding one third of our public equity float. The registration statement is intended to give us the flexibility to sell securities if and when market conditions and circumstances warrant, to provide funding for growth or other strategic initiatives, for debt reduction or refinancing and for other general corporate purposes. The actual amount and type of securities or combination of securities and the terms of those securities will be determined at the time of sale, if such sale occurs. If and when a particular series of securities is offered, the prospectus supplement relating to that offering will set forth our intended use of the net proceeds. In addition, we have entered into an at-the-market issuance sales agreement with a sales agent relating to the offering from time to time of shares of our common stock under the shelf registration statement. Sales of shares of our common stock, if any, may be made directly on the NASDAQ Global Market, on any other existing trading market for the common stock or through a market maker, or in privately negotiated transactions, subject to our approval. Our sales agreement is limited to the sale of up to a number of shares of common stock with an initial offering price not to exceed the amount that can be sold under the registration statement. As of the date of the sales agreement, such amount is limited to approximately $20.3 million. As of December 31, 2011, we had not issued any shares of common stock pursuant to the sales agreement.

From time to time, we may issue equity to fund certain transactions, such as our CEP investment and the settlement of our QER Loan that occurred in 2011, or to raise additional capital. On February 9, 2012, we issued 2,180,233 shares of our common stock to White Deer for proceeds of $7.5 million which were used to retire the Secured Pipeline Loan and for other general corporate purposes.

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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, 2011.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
	(In thousands)				
Borrowing Base Facility	$ 190,000	$	$ 190,000	$	$
Secured Pipeline Loan	3,000	3,000			
Interest expense on bank credit facilities	13,097	8,706	4,391		
Purchase obligations	700	482	213	4	1
Operating lease obligations	6,006	2,172	1,946	1,467	421
Total commitments	$ 212,803	$ 14,360	$ 196,550	$ 1,471	$ 422

Off-Balance Sheet Arrangements and Letters of Credit

At December 31, 2011, 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, 2011, we had $ 1.6 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.

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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 the 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.

Beginning with the quarter ended December 31, 2009, the ceiling test was calculated using a twelve-month average price and adjusted for basis differentials. In addition, subsequent to the adoption of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 400-20 *Retirement and Environmental Obligations-Asset Retirement Obligation*, the future cash outflows associated with settling 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 depreciation 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. For the year ended December 31, 2011, we increased our asset retirement liability to plug, abandon and dismantle wells by $3.9 million as a result of a revision in the future costs of those activities.

We have not recorded any asset retirement obligations relating to our gathering systems at December 31, 2010 and 2011 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 9 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 may 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*. 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, 2011, we recognized a total gain on derivative financial instruments in the amount of $35.4 million, consisting of a $33.7 million realized gain and a $1.7 million unrealized gain. We currently estimate the fair value of our commodity swaps with a discounted cash flow model utilizing, when possible, published forward commodity price curves and credit adjusted discount rates.

Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of 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. At December 31, 2010 and 2011, a full valuation allowance was recorded against our deferred tax assets.

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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 11 in Part II, Item 8. of this Annual Report on Form 10-K for further discussion of these limitations.

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 issued 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 is 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, while the provisions requiring gross presentation of activity within Level 3 assets were adopted beginning with the quarter ended March 31, 2011. The adoption did not materially affect our financial statements.

In May 2011, the FASB issued ASU 2011-04 *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*. ASU 2011-04 clarifies the principles and definitions used to measure fair value and expands disclosure requirements in order to achieve greater consistency between U.S. GAAP and International Financial Reporting Standards. The amendment does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. ASU 2011-04 is to be applied prospectively and is effective during interim and annual periods beginning after December 15, 2011. The amendment will not have a material impact on our financial statements.

In June 2011, the FASB issued ASU 2011-*05 Comprehensive Income (Topic 220): Presentation of Comprehensive Income*. ASU 2011-05 requires that all nonowner changes in stockholders equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two-statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of other comprehensive income and the total of comprehensive income. Certain provisions in this update relating to the new presentation for reclassifications of items out of accumulated other comprehensive income have been delayed indefinitely. The remaining amendments are to be applied retrospectively and are effective for fiscal years and interim periods within those years beginning after December 15, 2011. The amendment will not have a material impact on our financial statements.

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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 $113.93 per barrel in April 2011 to a low of $75.67 per barrel in October 2011, with an average of approximately $95.11 per barrel in 2011. Meanwhile, NYMEX natural gas futures prices ranged from a high of $4.847 per Mmbtu in June 2011 to a low of $2.989 per Mmbtu in December 2011, with an average of approximately $4.026 per Mmbtu in 2011. 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 natural gas prices are not at levels that warrant actively hedging. When prices improve, we intend to resume our natural gas 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).

	2009	2010	2011
Realized gain (loss)	$ 98,148	$ 31,932	$ 33,692
Unrealized gain (loss)	(50,026)	41,184	1,737
Total gain from derivative financial instruments	$ 48,122	$ 73,116	$ 35,429

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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, 2011.

	Year Ending December 31,		
	2012	2013	Total
	($ in thousands, except volumes and per unit data)		
Natural Gas Swaps			
Contract volumes (Mmbtu)	11,000,004	9,000,003	20,000,007
Weighted-average fixed price per Mmbtu	$ 7.13	$ 7.28	$ 7.20
Fair value, net	$ 42,803	$ 29,516	$ 72,319
Natural Gas Basis Swaps			
Contract volumes (Mmbtu)	9,000,000	9,000,003	18,000,003
Weighted-average fixed price per Mmbtu	$ (0.70)	$ (0.71)	$ (0.71)
Fair value, net	$ (4,767)	$ (4,611)	$ (9,378)
Crude Oil Swaps			
Contract volumes (Bbl)	42,000		42,000
Weighted-average fixed price per Bbl	$ 87.90	$	$ 87.90
Fair value, net	$ (456)	$	$ (456)
Total fair value, net	**$ 37,580**	**$ 24,905**	**$ 62,485**

In February 2012, we entered into new crude oil swap agreements for the following quantities and prices:

	Year Ending December 31,				
	2012	2013	2014	2015	2016
Crude Oil Swaps					
Contract volumes (Bbl)	20,570	65,892	61,680	58,164	53,892
Weighted-average fixed price per Bbl	$ 104.00	$ 101.70	$ 97.00	$ 93.40	$ 91.10

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. At December 31, 2011, we had outstanding $193.0 million of variable-rate debt. A 1% increase in our interest rates would increase gross interest expense approximately $1.9 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.

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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, 2011. Based on that evaluation, our principal executive officer and principal financial officer concluded that, as of December 31, 2011, 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, 2011, was effective based on the criteria set forth in the COSO Framework.

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Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting that occurred during the fourth quarter of 2011 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 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***

None.

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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.

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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

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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, 2011 and 2010, and the related consolidated statements of operations, cash flows and equity of the Company for year ended December 31, 2011, the period from March 6, 2010 to December 31, 2010 and of the Predecessors for the period from January 1, 2010 to March 5, 2010 and the year ended December 31, 2009. 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, 2011 and 2010, and the related consolidated statements of operations, cash flows and equity of the Company for the year ended December 31, 2011, the period from March 6, 2010 to December 31, 2010 and of the Predecessors for the period from January 1, 2010 to March 5, 2010 and the year ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas

March 8, 2012

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POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2011
	($ in thousands, except share and per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 730	$ 349
Accounts receivable trade, net	11,845	9,123
Other receivables	1,153	1,267
Inventory	6,161	1,788
Other current assets	2,799	7,492
Derivative financial instruments	31,588	42,803
Total	54,276	62,822
Oil and natural gas properties, full cost method of accounting, net	116,488	124,068
Pipeline assets, net	61,148	59,088
Other property and equipment, net	15,964	14,726
Other noncurrent assets, net	9,303	3,497
Equity investment		12,994
Derivative financial instruments	39,633	29,516
Total assets	$ 296,812	$ 306,711
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 7,030	$ 6,286
Revenue payable	5,898	4,972
Accrued expenses and other current liabilities	7,190	8,700
Litigation reserve	1,020	3,081
Current portion of long-term debt	10,500	3,000
Derivative financial instruments	3,792	5,223
Total	35,430	31,262
Derivative financial instruments	6,681	4,611
Long term debt	209,721	190,000
Asset retirement obligations	7,150	11,733
Other noncurrent liabilities		4,559
Total liabilities	258,982	242,165
Commitments and contingencies		
Series A Cumulative Redeemable Preferred Stock, $0.01 par value; issued and outstanding 6,000 shares	50,622	56,736
Stockholders equity		
Preferred stock, $0.01 par value; 5,000,000 authorized shares; 195,842 and 215,662 Series B Voting Preferred Stock issued and outstanding, respectively	2	2
Common stock, $0.01 par value; 40,000,000 authorized shares; 8,238,982 and 9,935,337 issued and outstanding, respectively	82	99
Additional paid-in capital	377,538	378,093
Accumulated deficit	(390,414)	(370,384)

Total (deficit) equity	(12,792)	7,810
Total liabilities and equity	$ 296,812	$ 306,711

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

	(Predecessors) Year Ended December 31, 2009	January 1, 2010 to March 5, 2010	March 6, 2010 to December 31, 2010	Year Ended December 31, 2011
	($ in thousands, except per share data)			
Revenue				
Oil and gas sales	$ 79,893	$ 18,659	$ 69,277	$ 79,887
Gathering	7,760	1,076	4,771	5,239
Pipeline	18,428	1,749	8,380	11,183
Total	106,081	21,484	82,428	96,309
Costs and expenses				
Production expense	55,961	8,645	38,329	47,136
Pipeline expense	6,573	1,110	5,195	5,219
General and administrative	40,693	5,735	19,065	17,199
Litigation reserve	1,030		1,640	11,592
Depreciation, depletion and amortization	47,802	4,164	18,683	27,662
(Gain) loss on disposal of assets	25		(13,495)	(10,560)
Impairments	268,630			
Recovery of misappropriated funds	(3,412)		(1,592)	
Total	417,302	19,654	67,825	98,248
Operating income (loss)	(311,221)	1,830	14,603	(1,939)
Other income (expense)				
Gain from derivative financial instruments	48,122	25,246	47,870	35,429
Loss from equity investment				(4,607)
Gain on forgiveness of debt			2,909	1,647
Other income (expense)	108	(4)	(24)	207
Interest expense	(29,573)	(5,340)	(20,169)	(10,710)
Interest income	244	4	32	3
Total	18,901	19,906	30,618	21,969
Income (loss) before income taxes	(292,320)	21,736	45,221	20,030
Income taxes				
Net income (loss)	(292,320)	21,736	45,221	20,030
Net (income) loss attributable to noncontrolling interests	147,398	(9,958)		
Net income (loss) attributable to controlling interests	(144,922)	11,778	45,221	20,030
Preferred stock dividends			(1,980)	(7,779)
Accretion of redeemable preferred stock			(327)	(1,580)
Net income (loss) available to common stockholders	$ (144,922)	$ 11,778	$ 42,914	$ 10,671
Net income (loss) per share common share				
Basic	$ (4.55)	$ 0.37	$ 5.29	$ 1.21
Diluted	$ (4.55)	$ 0.36	$ 4.62	$ 0.71

Weighted average common shares outstanding				
Basic	31,833	32,137	8,110	8,786
Diluted	31,833	32,614	9,295	15,050

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

	(Predecessors) Year Ended December 31, 2009	January 1, 2010 to March 5, 2010	March 6, 2010 to December 31, 2010	Year Ended December 31, 2011
	($ in thousands)			
Cash flows from operating activities				
Net income (loss)	$ (292,320)	$ 21,736	$ 45,221	$ 20,030
Adjustments to reconcile net income (loss) to cash provided by operations				
Depreciation, depletion and amortization	47,802	4,164	18,683	27,662
Impairments	268,630			
Stock-based compensation	1,279	808	1,635	1,258
Amortization of deferred loan costs	7,761	2,094	5,753	1,709
Change in fair value of derivative financial instruments	50,026	(21,573)	(19,611)	(1,737)
Litigation reserve	1,030		270	6,042
Recovery of misappropriated funds, net of liabilities assumed	(977)		(487)	
Loss (Gain) on disposal of assets	25		(13,495)	(10,560)
(Gain) on forgiveness of debt			(2,909)	(1,647)
Loss from equity investment				4,607
Other non-cash changes to items affecting net loss	1,000		138	618
Change in assets and liabilities				
Accounts receivable	10,173	777	2,201	2,696
Other current assets	1,461	466	(486)	(1,281)
Other assets	193	2	(3,224)	(649)
Accounts payable	(27,641)	(240)	(4,613)	(2,521)
Accrued expenses	6,112	983	465	(3,502)
Other	65		17	(17)
Cash flows from operating activities	74,619	9,217	29,558	42,708
Cash flows from investing activities				
Restricted cash	(159)	(1)	691	28
Proceeds from sale of equity securities				1,634
Equity investment				(12,883)
Equipment, development, leasehold and pipeline	(8,426)	(2,282)	(25,858)	(29,338)
Proceeds from sale of assets	8,898		14,062	12,723
Cash flows from investing activities	313	(2,283)	(11,105)	(27,836)
Cash flows from financing activities				
Proceeds from debt	4,300	900	2,100	3,000
Repayments of debt	(67,413)	(41)	(102,023)	(18,319)
Proceeds from stock option exercise				66
Debt and equity financing costs	(4,720)		(6,477)	
Proceeds from issuance of preferred stock and warrants			60,000	
Cash flows from financing activities	(67,833)	859	(46,400)	(15,253)
Net increase (decrease) in cash	7,099	7,793	(27,947)	(381)

Cash and cash equivalents beginning of period	13,785	20,884	28,677	730
Cash and cash equivalents end of period	$ 20,884	$ 28,677	$ 730	$ 349

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

	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	Total (Deficit) Equity
					($ in thousands, except share amounts)						
Predecessors											
Balance, December 31, 2008		$	32,224,643	$ 33	$ 298,583	21,955	$ (7)	$ (302,491)	$ (3,882)	$ 204,536	$ 200,654
Stock-based compensation					427				427	852	1,279
Restricted stock grants, net of forfeitures			(64,522)								
Net loss								(144,922)	(144,922)	(147,398)	(292,320)
Balance, December 31, 2009		$	32,160,121	$ 33	$ 299,010	21,955	$ (7)	$ (447,413)	$ (148,377)	$ 57,990	$ (90,387)
Stock-based compensation					210				210	598	808
Restricted stock grants, net of forfeitures			(1,687)								
Net income								11,778	11,778	9,958	21,736
Balance, March 5, 2010		$	32,158,434	$ 33	$ 299,220	21,955	$ (7)	$ (435,635)	$ (136,389)	$ 68,546	$ (67,843)
PostRock											
Balance, March 6, 2010		$		$	$		$	$	$	$	$
Issuance to Predecessors shareholders upon recombination			1,847,458	18	299,228			(435,635)	(136,389)		(136,389)
Issuance to Predecessors noncontrolling interests upon recombination			6,191,516	62	68,484				68,546		68,546
Stock-based compensation				2	1,633				1,635		1,635
Restricted stock grants, net of forfeitures			200,008								
Issuance of Series B preferred stock	195,842	2							2		2
Issuance of warrants					11,685				11,685		11,685
Cost of issuing preferred stock and warrants					(1,185)				(1,185)		(1,185)
Preferred stock dividends					(1,980)				(1,980)		(1,980)
Preferred stock accretion					(327)				(327)		(327)
Net income								45,221	45,221		45,221
Balance, December 31, 2010	195,842	$ 2	8,238,982	$ 82	$ 377,538		$	$ (390,414)	$ (12,792)	$	$ (12,792)
			75,169	1	1,252				1,253		1,253

Stock-based compensation										
Restricted stock grants net of forfeitures			460,000	5				5		5
Issuance of common stock			1,141,186	11	4,833			4,844		4,844
Issuance of Series B Preferred Stock	19,820									
Issuance of warrants					3,763			3,763		3,763
Stock option exercises			20,000		66			66		66
Preferred stock accretion					(1,580)			(1,580)		(1,580)
Preferred stock dividends					(7,779)			(7,779)		(7,779)
Net income							20,030	20,030		20,030
Balance December 31, 2011	215,662	$ 2	9,935,337	$ 99	$ 378,093	$	$ (370,384)	$ 7,810	$	$ 7,810

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) was formed in 2009 to combine its predecessor entities, Quest Resource Corporation (QRCP), Quest Energy Partners, L.P. (QELP) and Quest Midstream Partners, L.P. (QMLP) (collectively, the Predecessors) into a single entity. On March 6, 2010, PostRock completed the recombination of these entities (the Recombination). Unless the context requires otherwise, references to the Company, we, us and our refer to PostRock and its subsidiaries from the date of the Recombination and to the Predecessors on a consolidated basis prior thereto.

The Company is an independent oil and gas 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 oil and gas producing properties in the Appalachian Basin. The 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).

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, 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.

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. During 2011, the Company began utilizing a controlled disbursement cash account which is funded when outstanding checks and electronic payments are presented for payment and an overdraft is the normal book balance. The Company s policy has been to fund these outstanding checks and electronic payments as they clear through the banking system with customer receipts and borrowings under its Borrowing Base Credit Facility (as defined below). The Company accounts for such outstanding checks and electronic payments that have been issued but

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POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

not cleared through the banking system by reporting them in accounts payable in its consolidated balance sheets and including the change in such amounts in cash flows from operating activities in its consolidated statements of cash flows. Outstanding checks and electronic payments included in accounts payable at December 31, 2011, amounted to $2.1 million.

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 estimated to be uncollectible are charged to operations in the period the reserve is established. The allowance for doubtful accounts was approximately $258,000 and $181,000 at December 31, 2010 and 2011, 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 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 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 an unweighted arithmetic first day of the month price for trailing average twelve-month 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

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 and cumulative drilling costs to date 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. The assessment includes consideration of numerous factors, including intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, assignment of proved reserves and economic viability of development if proved reserves are assigned. Any impairments of 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 $843,000 related to its acquisition, exploration and development activities for the period from March 6 to December 31, 2010 and $1.1 million for the year ended December 31, 2011. 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. Capitalized interest was $51,000 for the year ended December 31, 2011, while no interest was capitalized for the years ended December 31, 2009 and 2010.

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. Maintenance and repair costs are charged to operating expense as incurred.

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 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.

Intangible Assets The Company carries contract-related intangible assets that 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.

Equity Investment The Company elected to measure its investment in Constellation Energy Partners LLC (CEP) at fair value with changes in fair value included in the consolidated statement of operations. If the Company had not elected the fair value method, the investment would have qualified for the equity method of accounting, under which the Company s proportionate share of the investee s income would have been reported in the consolidated statement of operations.

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POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Asset Retirement Obligations Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 410, *Asset Retirement and Environmental Obligations* (ASC 410) requires that the fair value of an asset retirement cost and the corresponding liability should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company s legal obligations related to future plugging and abandonment of its natural gas and oil wells and interstate pipeline assets. 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 that there is a legal or contractual obligation to dismantle or dispose of the asset and reclaim or remediate any related property at the end of its useful life, 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 of accounting.

For those derivatives that do not meet the requirements for NPNS designation nor qualify for hedge accounting, the Company believes that such contracts 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 caption Derivative financial instruments. 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).

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

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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.

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 as evidenced by a contract. 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.

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 FASB 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. At December 31, 2010 and 2011, a full valuation allowance was recorded against the Company s net deferred tax assets.

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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 (warrants, stock options and restricted stock awards) and is calculated by dividing net income (loss) 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. Risk with respect to receivables at December 31, 2010 and 2011, 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 81%, 60% and 31% of oil and gas revenue for the years ended December 31, 2009, 2010 and 2011, respectively.

Fair Value The Company adopted the full provisions of FASB ASC 820 *Fair Value Measurements and Disclosures* 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 at 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 at 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 may be 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. Transfers of assets and liabilities between Level 1 and Level 2 are recognized at the end of a reporting period. The Company prioritizes the use of the highest level inputs available in determining fair value.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Recent Accounting Pronouncements

In January 2010, the FASB issued 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 is 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, while the provisions requiring gross presentation of activity within Level 3 assets were adopted beginning with the quarter ended March 31, 2011. The adoption did not materially affect the Company s financial statements.

In May 2011, the FASB issued ASU 2011-04 *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*. ASU 2011-04 clarifies the principles and definitions used to measure fair value and expands disclosure requirements in order to achieve greater consistency between U.S. GAAP and International Financial Reporting Standards. The amendment does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. ASU 2011-04 is to be applied prospectively and is effective during interim and annual periods beginning after December 15, 2011. The amendment will not have a material impact on the Company s financial statements.

In June 2011, the FASB issued ASU 2011-*05 Comprehensive Income (Topic 220): Presentation of Comprehensive Income*. ASU 2011-05 requires that all nonowner changes in stockholders equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two-statement approach, the first statement should present total net income and its components followed consecutively by a second statement that should present total other comprehensive income, the components of other comprehensive income and the total of comprehensive income. Certain provisions in this update relating to the new presentation for reclassifications of items out of accumulated other comprehensive income have been delayed indefinitely. The remaining amendments are to be applied retrospectively and are effective for fiscal years and interim periods within those years beginning after December 15, 2011. The amendment will not have a material impact on the Company s financial statements.

Note 3 Acquisitions and Divestitures

CEP Investment During 2011, the Company acquired from Constellation Energy Group, Inc. (CEG) a 26.4% voting interest in CEP in two separate transactions at a total cost of $17.6 million. In the first transaction, the Company acquired a 14.9% voting interest in CEP which included the right to appoint two directors to CEP s Board. The 14.9% voting interest consisted of 485,065 of CEP s outstanding Class A Member Interests,

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

representing all of the class, and 3,128,670 Class B Member Interests. In the second transaction, the Company acquired an additional 2,790,224 Class B Member Interests, bringing the Company s ownership to a combined 26.4% voting interest at December 31, 2011. The $17.6 million cost included $12.6 million of cash, 1,000,000 shares of the Company s common stock with a fair value of $4.1 million, warrants to acquire an additional 673,822 shares of the Company s common stock with a fair value of $518,000, and acquisition costs of $352,000. Of the warrants, 224,607 are exercisable for one year following issuance at an exercise price of $6.57 a share, 224,607 are exercisable for two years following issuance at $7.07 a share and 224,608 for three years following issuance at $7.57 a share.

The Class B Member Interests are traded on the New York Stock Exchange under the ticker symbol CEP with a closing price of $1.96 per unit at December 30, 2011.

CEP is focused on the acquisition, development and production of oil and natural gas properties as well as related midstream assets. All of its proved reserves are located in the Cherokee Basin in Kansas and Oklahoma, the Black Warrior Basin in Alabama, the Woodford Shale in the Arkoma Basin in Oklahoma and the Central Kansas Uplift in Kansas and Nebraska. Because PostRock and CEP each have the majority of their assets in the Cherokee Basin of Kansas and Oklahoma, the investment was made in an attempt to work with CEP to explore opportunities to reduce costs and enhance value for the companies respective investors.

Appalachia Basin Sale On December 24, 2010, the Company entered into an agreement with Magnum Hunter Resources Corporation (MHR) to sell certain oil and gas properties and related assets in West Virginia. The sale closed in three phases for a total of $44.6 million. The first phase closed in December 2010 for $28 million while the following two phases closed in January and June 2011 for a combined $16.6 million. The amount received for the first and second phases was paid half in cash and half in MHR common stock, while the amount received for the third phase was paid entirely in cash.

Of the proceeds received, $6.4 million was set aside in escrow to cover potential claims for indemnity and title defects. The total first and second closing escrowed amount of $5.9 million is to be released in June 2012 while the third closing escrowed amount of $564,000 is to be released in December 2012. These amounts are reflected in the consolidated balance sheet as a component of other current assets. If all of the amounts in escrow are released, the Company would receive a total of $1.5 million, which includes $843,000 in connection with the QER Loan (see Note 10 Long-Term Debt). The remaining amount would be released to the lender and a third-party and is reflected in the consolidated balance sheet in other current liabilities.

In general, no gains or losses are recognized upon the sale or disposition of oil and gas properties unless the deferral of gains or losses would significantly alter the relationship between capitalized costs and proved reserves of oil and gas. A significant alteration generally 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 three-phased sale described above. Gains of $13.7 million and $12.5 million, net of $728,000, and $2.6 million in selling costs and adjustments, were recorded in 2010 and 2011 related to the three phases of the sale. The corresponding reduction in the Company s oil and gas full cost pool for the three phases of the sale was $13.6 million and $1.5 million in 2010 and 2011, respectively.

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. The proceeds from the divestiture during 2009 reduced the full cost pool.

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Note 4 Other Balance Sheet Items

The following describes the components of the following consolidated balance sheet items at December 31, 2010 and 2011 (in thousands):

	2010	2011
Other current assets		
Prepaid fees and deposits	$ 1,417	$ 1,022
Equity securities	1,354	
Escrowed funds (1)		6,439
Other	28	31
Total	$ 2,799	$ 7,492
Other noncurrent assets		
Intangible assets	$ 968	$ 676
Deferred financing costs	4,010	2,270
Escrowed funds (1)	4,200	
Noncurrent deposits and other	125	551
Total	$ 9,303	$ 3,497
Accrued expenses and other current liabilities		
Interest	$ 584	$ 53
Employee-related costs and benefits	1,802	1,294
Non-income related taxes	1,971	41
Escrowed funds due to third parties (2)		4,981
Fees for services	1,640	1,042
Other	1,193	1,289
Total	$ 7,190	$ 8,700
Other noncurrent liabilities		
Litigation reserve (3)	$	$ 4,111
Lease termination costs		440
Other		8
Total	$	$ 4,559

(1) Escrowed funds relate to the proceeds from the Appalachian Basin sale (see Note 3). The escrowed funds are restricted to cover indemnities and title defects related to the sale. If there are no claims against escrow, $5.9 million is scheduled to be released in June 2012 with the remainder to be release in December 2012.

(2) The portion of escrowed funds from the Appalachian Basin sale that, upon release, will be payable to the Royal Bank of Canada (RBC) and a third party.

(3) Recorded at present value (see Note 14).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Intangible Assets Balances for the contract-related intangibles acquired in the KPC Pipeline acquisition were as follows at December 31, 2010 and 2011 (in thousands):

	2010	2011
Gross carrying amount	$ 9,934	$ 9,934
Accumulated amortization	(7,931)	(8,223)
Impairment	(1,035)	(1,035)
Net carrying amount	$ 968	$ 676

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 $292,000 in 2012, $250,000 in 2013 and $134,000 thereafter. Amortization expense related to those contracts was $3.3 million for the year ended December 31, 2009. Amortization for the periods from January 1 to March 5, 2010, and from March 6 to December 1, 2010, was $78,000 and $214,000, respectively. Amortization expense related to those contracts for the year ended December 31, 2011 was $292,000.

As discussed in Note 5, 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 Company s expense related to amortizing or writing off deferred financing costs was $7.8 million for the year ended December 31, 2009, $2.1 million and $5.7 million for the periods from January 1 to March 5 and from March 6 to December 31, 2010, respectively, and $1.7 million for the year ended December 31, 2011. These costs are included in interest expense. Included in the amounts above were $3.5 million and $1.8 million of write-offs of unamortized debt issuance costs for the year ended December 31, 2009, and for the period from March 6 to December 31, 2010, respectively. The write-offs were made in connection with substantial amendments of the Company s credit facilities during those periods.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5 Property

Oil and gas properties, pipeline assets and other property and equipment were comprised of the following at December 31, 2010 and 2011 (in thousands):

	2010	2011
Oil and gas properties under the full cost method of accounting		
Properties being amortized	$ 319,966	$ 346,896
Properties not being amortized	188	31
Total oil and gas properties, at cost	320,154	346,927
Less accumulated depletion, depreciation and amortization	(203,666)	(222,859)
Oil and gas properties, net	$ 116,488	$ 124,068
Pipeline assets, at cost (1)	$ 75,480	$ 75,651
Less accumulated depreciation	(14,332)	(16,563)
Pipeline assets, net	$ 61,148	$ 59,088
Other property and equipment at cost	$ 33,154	$ 31,018
Less accumulated depreciation	(17,190)	(16,292)
Other property and equipment, net	$ 15,964	$ 14,726

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	5 to 7 years

For the year ended December 31, 2009, depletion, depreciation and amortization expense (excluding impairment amounts discussed below) on oil and gas properties amounted to $35.5 million; depreciation expense on pipeline assets amounted to $5.0 million and depreciation expense on other property and equipment amounted to $3.5 million. 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 $496,000 and $2.5 million, respectively; and depreciation expense on other property and equipment amounted to $604,000 and $3.4 million, respectively. For the year ended December 31, 2011, depletion, depreciation and amortization expense on oil and gas properties amounted to $19.6 million; depreciation expense on pipeline assets amounted to $3.0 million; and depreciation expense on other property and equipment amounted to $4.1 million. During 2011, the Company elected to shorten the depreciable lives of selected vehicle and equipment property in its pipeline segment as well as technologically limited assets, including computer hardware and communication devices, in service throughout the Company. The overall impact of this change was to increase depletion, depreciation and amortization by $0.7 million and aligns the remaining depreciable lives for these assets along the lines of the demonstrated useful lives of these assets.

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Impairment of oil and gas properties At December 31, 2011, 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 2011 while no impairment was recorded during the prior quarters of 2011. The Company recorded impairments of $102.9 million for the year ended December 31, 2009, while no impairment was recorded for the year ended December 31, 2010.

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.

Note 6 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. 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. Specifically, the Company may utilize futures, swaps and options.

Derivative instruments expose the Company to counterparty credit risk. The Company s commodity derivative instruments are currently with several counterparties. The Company generally executes commodity derivative instruments under master agreements which allow it, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If the Company chooses to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

The Company monitors the creditworthiness of its counterparties; however, it is not able to predict sudden changes in counterparties creditworthiness. In addition, even if such changes are not sudden, it may be limited in its ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer its position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices as well as incur a loss. The Company includes a measure of counterparty credit risk in its estimates of the fair values of derivative instruments in an asset position.

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The Company does not designate its derivative financial instruments as hedging instruments for financial accounting purposes; as a result, it recognizes the change in the respective instruments fair value currently in earnings. The tables below outline the classification of derivative financial instruments on the consolidated balance sheet and their financial impact on the consolidated statements of operations at and for the periods indicated (in thousands):

Fair Value of Derivative Financial Instruments

Derivative Financial Instruments	Balance Sheet location	December 31, 2010	December 31, 2011
Commodity contracts	Current derivative financial instrument asset	$ 31,588	$ 42,803
Commodity contracts	Long-term derivative financial instrument asset	39,633	29,516
Commodity contracts	Current derivative financial instrument liability	(3,792)	(5,223)
Commodity contracts	Long-term derivative financial instrument liability	(6,681)	(4,611)
		$ 60,748	$ 62,485

	(Predecessors) 2009	(Predecessors) January 1 to March 5, 2010	March 6 to December 31, 2010	2011
Realized gain (1)	$ 98,148	$ 3,673	$ 28,259	$ 33,692
Unrealized gain (loss)	(50,026)	21,573	19,611	1,737
Total gain from derivative financial instruments	$ 48,122	$ 25,246	$ 47,870	$ 35,429

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

The following table summarizes the estimated volumes, fixed prices and fair value attributable to oil and gas derivative contracts at December 31, 2011.

	Year Ending December 31, 2012	Year Ending December 31, 2013	Total
	($ in thousands, except per unit data)		
Natural Gas Swaps			
Contract volumes (Mmbtu)	11,000,004	9,000,003	20,000,007
Weighted-average fixed price per Mmbtu	$ 7.13	$ 7.28	$ 7.20
Fair value, net	$ 42,803	$ 29,516	$ 72,319
Natural Gas Basis Swaps			
Contract volumes (Mmbtu)	9,000,000	9,000,003	18,000,003

Weighted-average fixed price per Mmbtu	$	(0.70)	$	(0.71)	$	(0.71)
Fair value, net	$	(4,767)	$	(4,611)	$	(9,378)
Crude Oil Swaps						
Contract volumes (Bbl)		42,000				42,000
Weighted-average fixed price per Bbl	$	87.90	$		$	87.90
Fair value, net	$	(456)	$		$	(456)
Total fair value, net	**$**	**37,580**	**$**	**24,905**	**$**	**62,485**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the estimated volumes, fixed prices and fair value attributable to natural gas derivative contracts at December 31, 2010:

	Year Ending December 31, 2011	2012	2013	Total
	($ in thousands, except 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**

In February 2012, the Company entered into new crude oil swap agreements for the following quantities and prices:

	Year Ending December 31, 2012	2013	2014	2015	2016
Crude Oil Swaps					
Contract volumes (Bbl)	20,570	65,892	61,680	58,164	53,892
Weighted-average fixed price per Bbl	$ 104.00	$ 101.70	$ 97.00	$ 93.40	$ 91.10

Note 7 Financial Instruments

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

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.

In June 2011, the Company transferred 23,517 shares of MHR common stock with a fair value of $159,000 from Level 2 to Level 1 due to the limited amount of time remaining until restrictions on the Company s ability to trade these securities lapsed in July 2011. The lifting of restrictions enabled the Company to value these securities at published market prices. Following the lapse of restrictions, these securities were sold in July 2011 for approximately $168,000. There were no other movements between Levels 1 and 2 during the periods from January 1 to March 5 and March 6 to December 31, 2010, and for the year ended December 31, 2011.

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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). There were no purchases, sales or issuances during the time period presented.

	(Predecessors) January 1, 2010 to March 5, 2010	March 6, 2010 to December 31, 2010	Year Ended December 31, 2011
Balance at beginning of period	$ 1,530	$ 5,455	$ (9,853)
Realized and unrealized gains (losses) included in earnings	7,254	12,586	(2,025)
Transfers out of Level 3 (1)		(20,299)	9,949
Settlements	(3,329)	(7,595)	1,929
Balance at end of period	$ 5,455	$ (9,853)	$

(1) Availability of market based information allowed the Company to reclassify all if its swap contracts tied to Southern Star prices from Level 3 to Level 2 during the second quarter of 2011.

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 at December 31, 2011 and 2010 (in thousands):

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

At December 31, 2011	Level 1	Level 2	Level 3	Total Net Fair Value
Equity investment	$	$ 12,994	$	$ 12,994
Derivative financial instruments assets	$	$ 72,319	$	$ 72,319
Derivative financial instruments liabilities	$	$ (9,834)	$	$ (9,834)
Total	$	$ 75,479	$	$ 75,479

Commodity Derivative Instruments The Company s oil and gas derivative instruments may consist of variable to fixed price swaps, collars and basis swaps. When possible, 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 adjusted for counterparty credit risk. Counterparty credit risk is incorporated into derivative assets while the Company s own credit risk is incorporated into derivative liabilities. Both are based on the current published credit default swap rates.

Short-Term Investments At December 31, 2010, these investments consisted of 218,095 shares of MHR common stock received as proceeds from the Appalachia Basin sale described in Note 3, which were subsequently sold in June 2011 for $1.5 million. The fair value of these securities at December 31, 2010, was 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 at that time.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Equity Investment The Company s 26.4% voting interest in CEP at December 31, 2011, consists of 485,033 of CEP s outstanding Class A Member Interests and 5,918,894 Class B Member Interests. Fair value for the Class B Member Interests, which are publicly traded, is based on market price. Fair value for the Class A Member Interests is based on the market price of the publicly traded interests and a premium reflecting certain additional rights. At December 31, 2011, the fair values used for the Class A units and the Class B units were $2.87 and $1.96 per unit, respectively.

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 at December 31, 2010, were $68.5 million and $50.6 million, respectively. The fair value and the carrying value of these securities at December 31, 2011, were $62.2 million and $56.7 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 13.0% at December 31, 2011, which was based on companies with similar leverage 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 8 Equity Investment

The Company believes that its 26.4% voting interest in CEP at December 31, 2011, along with the right to appoint two directors to CEP s Board provide it the ability to exercise significant influence over the operating and financial policies of CEP. Rather than accounting for the investment under the equity method, the Company elected the fair value option to account for its interest in CEP at the first acquisition date on August 8, 2011. The fair value option was chosen as the Company determined that the market price of CEP s publicly traded interests provided a more accurate fair value measure of the Company s investment in CEP. The Company has not elected the fair value option for any of its other assets and liabilities. As a result of the decline in the market price of CEP s traded interests, the Company recorded a loss of $4.6 million for the year ended December 31, 2011. The loss was recorded as a component of other income (expense) in the consolidated statement of operations.

The following table presents summarized financial information of CEP for the year ended December 31, 2011.

	Year Ended December 31, 2011
Revenues	$ 105,217
Gross profit (1)	29,453
Net income from continuing operations	19,586
Net income	19,586

(1) Gross profit equals revenues less operating expenses

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9 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):

	(Predecessors) January 1 to March 5, 2010	March 6 to December 31, 2010	Year Ended December 31, 2011
Asset retirement obligations at beginning of year	$ 6,552	$ 6,648	$ 7,150
Liabilities incurred		41	171
Liabilities settled	(1)	(23)	(131)
Divestitures		(5)	(1)
Revision of estimates			3,896
Accretion	97	489	648
Asset retirement obligations at end of period or year	$ 6,648	$ 7,150	$ 11,733

During 2011, the Company had a legal obligation to plug, abandon and dismantle 30 inactive wells in the Cherokee Basin. The actual costs associated with these retirements were used to review and revise the Company s current asset retirement obligation estimates. In reviewing current estimates against actual costs incurred in 2011, the Company increased its reserve amount by $3.9 million. The increase was primarily due to an increase in labor and third party costs required to perform the necessary remediation.

Note 10 Long-Term Debt

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

	December 31, 2010	December 31, 2011
Borrowing Base Facility	$ 187,000	$ 190,000
Secured Pipeline Loan	13,500	3,000
QER Loan	19,721	
Total debt	220,221	193,000
Less current maturities included in current liabilities	10,500	3,000
Total long-term debt	$ 209,721	$ 190,000

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 $350 million secured borrowing base facility with a current borrowing base of $200 million, and is guaranteed by PostRock and certain of its subsidiaries.

At December 31, 2011, based on outstanding borrowings of $190.0 million and $1.6 million in letters of credit, the remaining availability under this facility was $8.4 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

- 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 financial covenants under the Borrowing Base Facility at December 31, 2011.

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, 2011, was 4.57%.

Maturity Date June 30, 2013.

Borrowing Base Redetermination The first borrowing base redetermination with respect to the indebtedness under the Borrowing Base Facility was made on July 31, 2011, based on the Company s March 31, 2011, oil and gas reserves. The borrowing base is determined based on the value of reserves at the Company s lenders forward price forecasts, which are generally derived from futures prices. As a result of the significant decline in lender forward price forecasts since the Company s prior borrowing base determination and the roll off of hedges, the borrowing base was reduced from $225 million to $200 million.

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

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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.

The Company was in compliance with all its financial covenants under the Secured Pipeline Loan at December 31, 2011. The Company repaid the outstanding balance on the Secured Pipeline Loan in full on its maturity date of February 28, 2012.

QER Loan

In connection with the restructuring of the Company s credit facilities in 2010, the Company entered into an asset sale agreement with RBC that allowed the Company to sell PostRock Eastern Production, LLC, formerly named Quest Eastern Resource LLC (QER), or its assets and, in the event the proceeds were not adequate to repay the QER Loan in full, the Company agreed to pay a portion of such shortfall in cash, stock or a combination thereof.

As discussed in Note 3, the Company sold certain Appalachian Basin oil and gas properties to MHR in three phases that closed in December 2010, January 2011 and June 2011. Included in the $44.6 million total was approximately $41.6 million representing the purchase price of assets owned by QER pledged as collateral under the QER Loan. From the sale proceeds, QER made payments to the lender, RBC, in the amount of $21.2 million in December 2010, $9.3 million in January 2011 and $4.3 million in June 2011. The $9.3 million payment in January 2011 consisted of $5.7 million in MHR common stock and $3.6 million in cash while the $4.3 million payment in June 2011 was entirely in cash. Concurrent with the June 2011 payment and pursuant to the terms of an asset sale agreement with RBC, the Company fully settled the outstanding balance of the QER Loan of approximately $843,000 by issuing 141,186 shares of its common stock with a fair value of $744,000 to RBC. The Company expects to recover the full amount of the $843,000 payment to RBC in June 2012.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The settlement of the QER Loan was facilitated by the restructuring of a prior loan that met the criteria under accounting guidance to be classified as a troubled debt restructuring. The Company had previously recorded a gain on debt restructuring related to the QER Loan of $2.9 million in 2010. Following a re-evaluation of the maximum sum of future cash flows that would be paid to RBC, the Company recorded an additional gain of $1.6 million during the second quarter of 2011. The gain includes $799,000 of accrued interest that was forgiven at the time the balance of the loan was settled. The gain is reflected as a gain on forgiveness of debt in the consolidated statement of operations.

Note 11 Income Taxes

The Company has not recorded any provision or benefit for income taxes for the years ended December 31, 2009, 2010 and 2011.

A reconciliation of federal income taxes at the statutory federal rates to our actual provision for income taxes for the year ended December 31, 2009 and 2011, and for the periods from January 1 to March 5, 2010, and March 6 to December 31, 2010, are as follows (in thousands):

	(Predecessors)			
	2009	January 1 to March 5, 2010	March 6 to December 31, 2010	2011
Income tax expense (benefit) at statutory rate	$ (50,723)	$ 4,122	$ 15,828	$ 7,011
State income tax expense (benefit), net of federal	(3,131)	289	(651)	647
Effect of the Recombination			(22,170)	
Other	2,548	318	(3,673)	2,942
IRC Section 382 limitation		3,628	71,377	(2,135)
Change in valuation allowance	51,306	(8,357)	(60,711)	(8,465)
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 at each reporting period, the Company recorded a full valuation allowance against its net deferred tax asset at December 31, 2009, 2010, and 2011.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred tax assets and liabilities at December 31, 2010 and 2011 were as follows (in thousands):

	2010	2011
Current deferred income tax assets		
Unrealized loss for commodity derivative recorded for book, not for tax	$ 1,414	$ 1,947
Accrued liabilities	1,416	4,100
Allowance for bad debts	96	67
Total current deferred income tax assets	2,926	6,114
Noncurrent deferred income tax assets		
Unrealized loss for commodity derivative recorded for book, not for tax	2,490	1,719
Partnership basis differences		2,191
Property and equipment	91,942	74,144
Asset retirement obligations	1,966	2,208
Net operating loss carryforwards	12,126	22,312
Other carryforwards	38	43
Other	1,909	2,066
Total noncurrent deferred income tax assets	110,471	104,683
Total deferred income tax assets	113,397	110,797
Current deferred income tax liabilities		
Unrealized gain for commodity derivative recorded for book, not for tax	(11,774)	(15,955)
Other		(1,698)
Total current deferred income tax liabilities	(11,774)	(17,653)
Noncurrent deferred income tax liabilities		
Unrealized gain for commodity derivative recorded for book, not for tax	(14,773)	(11,002)
Other	(1,084)	
Total noncurrent deferred income tax liabilities	(15,857)	(11,002)
Total deferred income tax liabilities	(27,631)	(28,655)
Net deferred income tax assets	85,766	82,142
Valuation allowance	(85,766)	(82,142)
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 2031.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ownership changes within the meaning of IRC Section 382 on November 14, 2005, March 5, 2010, and September 21, 2010. The Company has NOL carryforwards of approximately $254 million at December 31, 2011 that are available to reduce future U.S. taxable income in certain circumstances. At December 31, 2011, $228 million of federal NOL carryforwards are subject to the IRC Section 382 limitation and it is anticipated that $207 million of these federal NOL carryforwards will expire unused due to the IRC Section 382 limitation. As a result, only $47 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, 2011.

In December 2010, certain assets located in Wetzel County, West Virginia, were sold to MHR (see Note 3), resulting in a recognized built-in loss of $5.0 million. The Company also had recognized built-in losses of $46.8 million due to depreciation and depletion expense limitations as a result of the ownership changes that occurred in March and September of 2010. It is anticipated that $50.8 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 has no amounts recorded for uncertain tax benefits at December 31, 2011. 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, 2008, 2009 and 2010 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, 2007, 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.

Note 12 Redeemable Preferred Stock and Warrants

On September 21, 2010, the Company issued to White Deer Energy L.P. and its affiliates (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 initial 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 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 as additional liquidation preference. Subsequent to July 1, 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 does not vote generally with the common stock, but has 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.

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. At January 1, 2012, with respect to the votes applicable to the Series B Preferred Stock, the holders of the Series B Preferred Stock and their affiliates are limited to 45% of the votes applicable to all outstanding voting stock; such holders and their affiliates may vote any shares of common stock held by them without regard to that limit.

When the Company accrues dividends on its Series A Preferred Stock on a quarterly dividend payment date, it records the increase in liquidation preference and the issuance of additional warrants by allocating their relative fair values to the amount of accrued dividends. The allocation results in an increase to the Company s temporary equity related to the Series A Preferred Stock and an increase to additional paid in capital related to the additional warrants issued. The increase to additional paid in capital related to additional warrants issued was $872,000 and $3.2 million for the years ended December 31, 2010 and 2011, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes changes in the Series A Preferred Stock and associated warrants since White Deer s initial investment on September 21, 2010.

	Carrying Value of Series A Preferred Stock	Number of Outstanding Series A Preferred Shares	Liquidation Value of Series A Preferred Stock	Number of Outstanding Warrants	Weighted Average Exercise Price of Warrants
Initial issuance	$ 49,188	6,000	$ 60,000	19,047,619	$ 3.15
Accrued dividends	1,107		1,980	536,586	3.69
Accretion	327				
December 31, 2010	$ 50,622	6,000	$ 61,980	19,584,205	$ 3.16
Accrued dividends	4,534		7,779	1,982,040	3.92
Accretion	1,580				
December 31, 2011	$ 56,736	6,000	$ 69,759	21,566,245	$ 3.23

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* 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.

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 with an additional 2,000,000 shares authorized in 2011. 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 Predecessors and the Predecessors consolidated subsidiaries recognized $393,000 of compensation expense related to the accelerated vesting discussed above. All remaining unvested awards were converted to 595,923 PostRock restricted share awards.

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

	Number of Non-Vested Restricted Shares	Weighted Average Grant-Date Fair Value
Predecessors		
Non-vested restricted shares at December 31, 2008	482,376	$ 8.01
Granted (a)	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 (b)	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

	Number of Non-Vested Restricted Shares	Weighted Average Grant-Date Fair Value
PostRock		
Non-vested restricted shares at March 6, 2010		$
Converted upon Recombination (c)	595,923	4.67
Granted (d)	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
Granted (e)	487,500	2.90
Vested	(80,554)	5.91
Forfeited	(203,094)	5.08
Non-vested restricted shares at December 31, 2011	579,210	$ 3.33

(a) 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.

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

(c) 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.

(d) 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(e) Consists of restricted shares granted to employees of which 51,500 shares vest in one year and 436,000 shares vest 33% each year for three years.

At December 31, 2011, total unrecognized stock-based compensation expense related to non-vested restricted shares was $1.4 million, which is expected to be recognized over a weighted average period of approximately 1.47 years while 1,244,064 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 granted stock options to employees and non-employees. Option grants under the LTIP expire 5-10 years following the date of grant.

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

	Stock Options	Weighted Average Exercise Price per Share
Predecessors		
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
Granted	799,400	3.63

Exercised (b)	(20,000)		3.29
Forfeited	(289,600)		4.07
Options outstanding at December 31, 2011	1,056,850		3.59
Options exercisable at December 31, 2011	245,750	$	5.57

(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. At March 1, 2012, all of these stock options have been forfeited.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(b) The Company received $66,000 upon exercise of these options which had a total intrinsic value of $34,000 at the exercise dates.
During 2011, PostRock granted 170,000 stock options to its non-employee directors that vested immediately and 629,400 stock options to employees that vest ratably over a three year period. The weighted average grant date fair value of stock options granted during 2011 was $2.15 per option. The weighted average grant date fair value of stock options granted in the Predecessor period in 2009, which were for the purchase of QRCP common stock, was $0.45 per share. The weighted average grant date fair value of stock options granted in 2010, all of which were granted subsequent to the Recombination for the purchase of PostRock common stock, was $2.28 per option.

The weighted average remaining term of options outstanding and options exercisable at December 31, 2011, was 4.65 and 4.31 years, respectively. Options outstanding and options exercisable at December 31, 2011, had an aggregate intrinsic value of approximately $169,000 and nil, respectively.

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, 2009, 2010 and 2011.

	(Predecessors) 2009	2010	2011
Expected option life years	10	5-6	5-6
Volatility	101.2%	75.2 84.1%	74.4 77.0%
Risk-free interest rate	4.93%	1.8 2.0%	0.9 2.0%
Dividend yield			
Fair value per share	$0.45	$2.24 $2.43	$1.43 $4.53

At December 31, 2011, 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 1.49 years.

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
Predecessors	
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
Year Ended December 31, 2011	1,258

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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):

	(Predecessors)			
	Year ended December 31, 2009	January 1, 2010 to March 5, 2010	March 6, 2010 to December 31, 2010	Year ended December 31, 2011
Net income (loss) attributable to controlling interests	$ (144,922)	$ 11,778	$ 45,221	$ 20,030
Preferred stock dividends			(327)	(1,580)
Preferred stock dividends			(1,980)	(7,779)
Net income (loss) attributable to common stockholders	$ (144,922)	$ 11,778	$ 42,914	$ 10,671
Denominator				
Common shares	31,833,222	32,016,327	8,110,348	8,785,551
Weighted average number of unvested share-based awards participating (1)		121,121		
Denominator for basic earnings per share	31,833,222	32,137,448	8,110,348	8,785,551
Effect of potentially dilutive securities				
Unvested share-based awards non-participating		450,751	81,815	127,600
Warrants			1,102,798	6,089,339
Stock options		26,154	123	47,230
Denominator for diluted earnings per share	31,833,222	32,614,353	9,295,084	15,049,720
Basic earnings per share	$ (4.55)	$ 0.37	$ 5.29	$ 1.21
Diluted earnings per share	$ (4.55)	$ 0.36	$ 4.62	$ 0.71
Securities excluded from earnings per share calculation				
Unvested share-based awards (2)	1,141,197			14,998
Antidilutive stock options	670,000	570,000	567,050	1,056,850
Warrants				1,830,464

(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, and for the year ended December 31, 2011, there were no unvested participating share-based awards.

(2) Restricted stock awards were excluded for the year ended December 31, 2009, because the Predecessors reported a net loss for that period.

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

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, would have a material adverse effect on its financial position, results of operations or cash flow.

The Company had been sued in royalty owner lawsuits filed in Oklahoma and Kansas. In Oklahoma, suits by a group of individual royalty owners and by a putative class representing all remaining royalty owners were filed in the District Court of Nowata County, Oklahoma. Generally, the lawsuits alleged that the Company wrongfully deducted post-production costs from the plaintiffs royalties and engaged in self-dealing agreements resulting in a less than market price for the gas production. The Company denied the allegations. Settlements were reached in each of the cases, and on July 28, 2011, the Court entered a final order approving the class action settlement. On July 29, 2011, the Company paid $5.6 million in settlement of both Oklahoma suits.

The Kansas lawsuit was a putative class action filed in the United States District Court for the District of Kansas, brought on behalf of all the Company s royalty owners in that state. Plaintiffs generally alleged that the Company failed to properly make royalty payments by, among other things, charging post-production costs to royalty owners in violation of the underlying lease contracts, paying royalties based on sale point volumes rather than wellhead volumes, allocating expenses in excess of the actual and reasonable post-production costs incurred, allocating production costs and marketing costs to royalty owners, and making royalty payments after the statutorily prescribed time for doing so without paying interest thereon. We denied plaintiffs claims. The parties reached a settlement and on December 30, 2011, the Court entered an order certifying a class for settlement purposes consisting of all current and former PostRock royalty and overriding royalty owners, approving the parties settlement and dismissing the action. The settlement includes a payment of $3.0 million that was made in January 2012, and a payment of $4.5 million to be made by January 31, 2013, for a total of $7.5 million.

At December 31, 2011, the Company had reserved $7.1 million for the estimated cost to resolve the Kansas action. The $7.1 million included the $3.0 million paid in January 2012 and $4.1 million representing the present value of an additional $4.5 million to be paid by January 31, 2013. The $4.1 million reserve is reflected in other noncurrent liabilities in the consolidated balance sheet. The Company recorded litigation reserve expense related to its Oklahoma and Kansas lawsuits of $11.5 million for the year ended December 31, 2011.

Environmental Matters At December 31, 2010 and 2011, 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 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, the Company also has operating leases for office space, warehouse facilities and office equipment expiring in various years through 2017.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Future minimum rental payments under all non-cancelable operating leases at December 31, 2011, were as follows (in thousands):

Year ending December 31,	
2012	$ 2,172
2013	1,045
2014	900
2015	771
2016	696
Thereafter	422
Total minimum lease obligations	$ 6,006

Total rental expense under cancelable and non-cancelable operating leases was $17.3 million for the year ended December 31, 2009, $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 $13.6 million for the year ended December 31, 2011.

Note 15 Supplemental Cash Flow Information

	(Predecessors)			
	Year Ended December 31, 2009	January 1 to March 5, 2010	March 6 to December 31, 2010	Year Ended December 31, 2011
		(In thousands)		
Cash paid for interest	$ 19,293	$ 2,686	$ 10,699	$ 8,623
Cash paid for income taxes				
Noncash investing activity				
Common stock issued for purchase of equity investment				4,100
Warrants issued for purchase of equity investment				518
Equity securities received on the sale of oil and gas properties			14,000	5,875
Noncash financing activity				
Reduction of debt through conveyance of financial securities received from sale of oil and gas properties			12,646	5,729
Reduction of debt through issuance of common stock				843
Issuance of preferred stock and warrants in lieu of cash dividends			1,980	7,779
Accretion of discount on redeemable preferred stock			327	1,580

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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. No additional recoveries were made during 2011.

Note 17 Operating Segments

In accordance with FASB ASC 280, *Segment Reporting,* 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.

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.

The Company s Chief Operating Decision Maker evaluates the performance of the reportable segments based on Income (Loss) before income taxes and noncontrolling interests. 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.

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Operating segment data for the periods indicated is as follows (in thousands):

	Production	Pipeline	Total
Predecessors			
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
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
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
Year Ended December 31, 2011			
Total revenues	$ 85,126	$ 11,183	$ 96,309
Segment operating profit (loss)	$ 24,459	$ 2,393	$ 26,852
Capital expenditures	$ 29,372	$ 881	$ 30,253
Depreciation, depletion and amortization	$ 24,088	$ 3,574	$ 27,662
Identifiable assets			
December 31, 2010	$ 232,111	$ 64,701	$ 296,812
December 31, 2011	$ 245,093	$ 61,618	$ 306,711

The following table reconciles segment operating profit reported above to loss before income taxes and non-controlling interests (in thousands):

	(Predecessors)			
	Year Ended December 31, 2009	January 1 to March 5, 2010	March 6 to December 31, 2010	Year Ended December 31, 2011
Segment operating profit (loss)	$ (272,910)	$ 7,565	$ 33,716	$ 26,852
General and administrative expenses	(40,693)	(5,735)	(19,065)	(17,199)
Recovery of misappropriation of funds	3,412		1,592	
Litigation reserve	(1,030)		(1,640)	(11,592)
Gain from derivative financial instruments	48,122	25,246	47,870	35,429
Interest expense, net	(29,329)	(5,336)	(20,137)	(10,707)
Gain on forgiveness of debt			2,909	1,647
Loss from equity investment				(4,607)
Other income (expense), net	108	(4)	(24)	207

Loss before income taxes and noncontrolling interests	$ (292,320)	$ 21,736	$ 45,221	$ 20,030

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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. Beginning in 2011, the Company contributed two percent of employees annual compensation regardless whether contributions were made by the employee. The Company would also match 100% of employee contributions in excess of two percent up to a total of four percent of annual compensation. Employees vest 50% in Company contributions in their second year of service and 100% in their third year of service. The Company made cash contributions to the plan of $426,000 for the year ended December 31, 2009, $63,000 from January 1 to March 5, 2010, $214,000 from March 6 to December 31, 2010 and $492,000 during the year ended December 31, 2011.

Note 19 Subsequent Events

On February 9, 2012, the Company issued 2,180,233 shares of its common stock to White Deer for proceeds of $7.5 million which were used to retire the Secured Pipeline Loan and for other general corporate purposes.

Note 20 Supplemental Financial Information Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2010 and 2011 are as follows (in thousands, except per share data):

	January 1 to March 5 (Predecessor)	March 6 to March 31	Quarters Ended June 30,	September 30,	December 31,
2010					
Total revenues	$ 21,484	$ 9,828	$ 23,826	$ 25,323	$ 23,451
Operating income (loss) (1)	1,830	644	(2,676)	4,462	12,173
Net income (loss)	21,736	17,010	(9,587)	28,189	9,609
Net income (loss) per common share					
Basic	$ 0.37	$ 2.12	$ (1.19)	$ 3.47	$ 0.91
Diluted	$ 0.36	$ 2.04	$ (1.19)	$ 3.21	$ 0.66

	Quarters Ended March 31,	June 30,	September 30,	December 31,
2011				
Total revenues	$ 24,766	$ 25,524	$ 24,427	$ 21,592
Operating income (loss) (1)	(685)	3,113	(1,499)	(2,868)
Net income (loss)	(3,861)	7,531	7,007	9,353
Net income (loss) per common share				
Basic	$ (0.74)	$ 0.63	$ 0.51	$ 0.72
Diluted	$ (0.74)	$ 0.28	$ 0.29	$ 0.69

(1) Total revenue less total costs and expenses.

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.

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Equity investment At December 31, 2011, the Company owned a 26.4% voting interest in CEP, a publicly traded oil and gas exploration and production company. CEP utilizes the successful efforts method of accounting for its oil and gas activities. Where applicable, the disclosures required under FASB ASC 932 are made below for the Company s proportionate share of CEP s oil and gas activities. Information utilized to prepare disclosures on the Company s proportionate share of CEP is based on publicly available data.

Net Capitalized Costs

Aggregate capitalized costs related to oil and gas producing activities of the Company at December 31, 2010 and 2011, are summarized as follows (in thousands):

	2010	2011
Oil and gas properties and related leasehold costs		
Proved	$ 319,966	$ 346,896
Unproved	188	31
	320,154	346,927
Accumulated depreciation, depletion and amortization	(203,666)	(222,859)
Net capitalized costs	$ 116,488	$ 124,068

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.

Aggregate capitalized costs related to oil and gas producing activities of the Company s 26.4% investment in CEP at December 31, 2011, are summarized as follows (in thousands):

	2011
Oil and gas properties and related equipment (successful efforts method)	
Proved	$ 207,263
Unproved	349
Materials, supplies and land	569
	208,181
Accumulated depreciation, depletion and amortization	(137,935)
Net capitalized costs	$ 70,246

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Costs Incurred

Costs incurred for oil and gas property acquisition, exploration and development activities that have been capitalized for the years ended December 31, 2009, 2010, and 2011 are summarized as follows (in thousands):

	Consolidated Entities			CEP (1)
	2009	2010 (2)	2011	2011
Proved property acquisition costs (1)(3)	$ 1,293	$ 1,364	$ 223	$ (74)
Unproved property acquisition costs	705	828	630	167
Exploration costs	128			
Development costs	5,087	27,396	23,825	2,895
	$ 7,213	$ 29,588	$ 24,678	$ 2,988

(1) Based on a pro-rata 26.4% interest in CEP assuming that the Company s investment was made as of January 1, 2011.
(2) Costs incurred for the period from January 1 to March 5, 2010, were $2.1 million.
(3) The amount is negative for CEP as it represents a post-closing receipt from an acquisition made by CEP in December 2010.

Results of Operations

The revenues and expenses associated directly with the Company s oil and natural gas producing activities are reflected in the consolidated statement of operations and within the segment disclosures of Note 17.

The table below presents the pro-rata results of oil and gas producing activities of the Company s investment in CEP for the year ended December 31, 2011, assuming that the Company s 26.4% investment was made as of January 1, 2011 (in thousands).

	2011
Revenues	$ 27,778
Lease operating expense	7,379
Cost of sales and production taxes	1,343
Exploration costs	35
Impairment of oil and gas properties	775
Depreciation, depletion and amortization	5,845

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. Cawley, Gillespie & Associates, Inc., independent reserve engineering firm, was retained to perform the annual year-end independent evaluation of the Company s 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

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POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

The table below presents changes in proved developed and undeveloped reserves of our consolidated entities. 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 at December 31, 2010, were subsequently 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 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, 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 (1)	92,244,096	(15,040)
Production	(19,225,006)	(76,583)
Balance, December 31, 2010	130,462,031	744,266
Purchase of reserves in place		
Extensions, discoveries, and other additions	1,752,746	54,761
Sale of reserves	(754,479)	
Revisions of previous estimates	5,068,946	352,981
Production	(18,309,056)	(78,087)
Balance, December 31, 2011	118,220,188	1,073,921
Proved developed reserves		
Balance, December 31, 2009	62,135,258	785,345
Balance, December 31, 2010 (1)	116,951,438	733,774
Balance, December 31, 2011	117,406,577	1,040,309

(1) 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.

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POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The table below presents the Company s 26.4% pro-rata share of changes in reserves and the amounts of proved developed reserves of CEP assuming that the Company s investment was made as of January 1, 2011.

Investment in CEP

	Mcfe
Balance, December 31, 2010	44,618,000
Purchase of reserves in place	
Extensions, discoveries, and other additions	455,000
Sale of reserves	
Revisions of previous estimates	11,216,000
Production	(3,138,000)
Balance, December 31, 2011	53,151,000
Proved developed reserves	
Balance, December 31, 2011	40,295,000

Standardized Measure of Discounted Future Net Cash Flows

The following information is based on the Company s best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows at December 31, 2009, 2010 and 2011 in accordance with FASB ASC 932 which requires the use of a 10% discount rate. Future income taxes are based on year-end statutory rates. This information is not the fair market value, nor does it represent the expected present value of future cash flows of Company s proved oil and gas reserves (in thousands).

	Consolidated Entities			CEP (1)
	2009	2010	2011	2011
Future cash inflows	$ 311,831	$ 617,947	$ 592,796	$ 241,173
Future production costs	202,645	335,688	312,410	132,081
Future development costs	17,398	26,941	10,524	25,705
Future income tax expense		14,937		
Future net cash flows	91,788	240,381	269,862	83,387
10% annual discount for estimated timing of cash flows	41,229	81,120	94,342	40,964
Standardized measure of discounted future net cash flows related to proved reserves	$ 50,559	$ 159,261	$ 175,520	$ 42,423

(1) Represents the Company s 26.4% pro-rata share of its investment in CEP.

Future cash inflows are computed by applying a twelve-month average price, 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.

	2009	2010	2011
Crude oil price per Bbl	$ 61.18	$ 79.43	$ 96.19
Natural gas price per Mmbtu	$ 3.87	$ 4.38	$ 4.12

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POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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):

	Consolidated Entities			CEP (1)
	2009	**2010**	**2011**	**2011**
Present value, beginning of period	$ 164,094	$ 50,559	$ 159,261	$ 34,765
Net changes in prices and production costs	(35,203)	23,107	11,876	38
Net changes in future development costs	20,727	(17,927)	(1,154)	
Previously estimated development costs incurred	5,292	17,515	18,192	1,892
Sales of oil and gas produced, net	(46,442)	(40,962)	(32,751)	(7,810)
Extensions and discoveries	50	895	3,045	2,157
Purchases of reserves in-place	283	15		
Sales of reserves in-place		(18,041)	(1,104)	
Revisions of previous quantity estimates	(63,230)	127,723	10,513	11,243
Net change in income taxes		(12,037)	12,037	
Accretion of discount	17,576	6,660	16,448	3,477
Timing differences and other (2)	(12,588)	21,754	(20,843)	(3,339)
Present value, end of period	$ 50,559	$ 159,261	$ 175,520	$ 42,423

(1) Represents the Company s pro-rata share of its investment in CEP assuming that the Company s 26.4% investment was made as of January 1, 2011.

(2) The change in timing differences and other are related to revisions in the Company s 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 8th day of March, 2012.

POSTROCK ENERGY CORPORATION

/s/ TERRY W. CARTER
Terry W. Carter
Chief Executive Officer and President

POWER OF ATTORNEY

By signing this Annual Report on Form 10-K below, I hereby appoint each of Terry W. Carter and David J. Klvac 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/ TERRY W. CARTER **Terry W. Carter**	Chief Executive Officer and President and Director (Principal Executive Officer)	March 8, 2012
/s/ DAVID J. KLVAC **David J. Klvac**	Executive Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer)	March 8, 2012
/s/ DUKE R. LIGON **Duke R. Ligon**	Chairman of the Board	March 8, 2012
/s/ NATHAN M. AVERY **Nathan M. Avery**	Director	March 8, 2012
/s/ WILLIAM H. DAMON III **William H. Damon III**	Director	March 8, 2012
/s/ THOMAS J. EDELMAN **Thomas J. Edelman**	Director	March 8, 2012
/s/ J. PHILIP MCCORMICK **J. Philip McCormick**	Director	March 8, 2012

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Name	Capacity	Date
/s/ JAMES E. SAXTON JR. **James E. Saxton Jr.**	Director	March 8, 2012
/s/ DANIEL SPEARS **Daniel Spears**	Director	March 8, 2012
/s/ MARK A. STANSBERRY **Mark A. Stansberry**	Director	March 8, 2012

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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).
2.4*	Purchase Agreement, dated August 8, 2011 (CEG Purchase Agreement), by and among PostRock, Constellation Energy Commodities Group, Inc. and Constellation Energy Partners Holdings, LLC (incorporated herein by reference to Exhibit 2.1 to PostRock s Current Report on Form 8-K filed on August 12, 2011).
2.5*	Purchase Agreement, dated December 19, 2011, by and among PostRock, Constellation Energy Partners Management LLC, Constellation Energy Commodities Group, Inc. and Constellation Energy Partners Holdings, LLC (incorporated herein by reference to Exhibit 2.1 to PostRock s Current Report on Form 8-K filed on December 23, 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).
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 with respect to the White Deer SPA (as defined below) (incorporated herein by reference to Exhibit 4.3 to PostRock s Current Report on Form 8-K filed on September 3, 2010).
4.5*	Form of Warrant with respect to the CEG Purchase Agreement (incorporated herein by reference to Exhibit 4.1 to PostRock s Current Report on Form 8-K filed on August 12, 2011).

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Exhibit No.	Description
10.1*	Securities Purchase Agreement dated September 2, 2010 (the White Deer SPA) 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*	First Amended and Restated Registration and Investor Rights Agreement, dated August 8, 2011, by and among PostRock Energy Corporation, Constellation Energy Commodities Group, Inc., 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 August 12, 2011).
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).
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).

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Exhibit No.	Description
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 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).
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 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 10.20 to PostRock s Annual Report on Form 10-K for the fiscal year ended December 31, 2010, filed on March 3, 2011).
10.21*	Consent and Reaffirmation of PostRock Energy Services Corporation and PostRock, dated February 21, 2011 (incorporated herein by reference to Exhibit 10.21 to PostRock s Annual Report on Form 10-K for the fiscal year ended December 31, 2010, filed on March 3, 2011).

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Exhibit No.	Description
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 quarter 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 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).
10.28*	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).
10.29*	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).
10.30*	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).
10.31*	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).
10.32*	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).
10.33	Amendment No. 1 to PostRock 2010 Long-Term Incentive Plan.
10.34*	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).

Exhibit No.	Description
10.35*	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 for the quarter ended March 31, 2010, filed on May 13, 2010).
10.36*	PostRock 2010 Long-Term Incentive Plan Form of 2011 Restricted Share Award Agreement (incorporated herein by reference to Exhibit 10.1 to PostRock s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed on May 11, 2011).
10.37*	PostRock 2011 Management Incentive Program (incorporated herein by reference to Exhibit 10.2 to PostRock s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed on May 11, 2011).
10.38*	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).
10.39*	PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (immediate vesting) (incorporated herein by reference to Exhibit 10.50 to PostRock s Annual Report on Form 10-K for the fiscal year ended December 31, 2010, filed on March 3, 2011).
10.40*	PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (one-year vesting) (incorporated herein by reference to Exhibit 10.51 to PostRock s Annual Report on Form 10-K for the fiscal year ended December 31, 2010, filed on March 3, 2011).
10.41*	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).
10.42*	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).
10.43*	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).
10.44*	Summary of certain director compensation matters (incorporated herein by reference to Exhibit 10.11 to PostRock s Quarterly Report on Form 10-Q for the quarter ended September 30, 2010, filed on November 10, 2010).
10.45*	At-The-Market Issuance Sales Agreement dated August 23, 2011 between PostRock Energy Corporation and McNicoll, Lewis & Vlak LLC (incorporated herein by reference to Exhibit 10.1 to PostRock s Current Report on Form 8-K filed on August 24, 2011).
10.46*	First Amendment to Amended and Restated Pledge and Security Agreement, dated as of August 1, 2011, among PostRock Energy Services Corporation, PostRock MidContinent Production, LLC, STP Newco, Inc. and the Collateral Agent (incorporated herein by reference to Exhibit 10.3 to PostRock s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, filed on November 9, 2011).
10.47*	Assumption Agreement executed by PostRock Eastern Production, LLC, dated as of August 1, 2011 (incorporated herein by reference to Exhibit 10.4 to PostRock s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, filed on November 9, 2011).
10.48*	Guaranty (Subsidiary) executed by PostRock Eastern Production, LLC, dated July 31, 2011 (incorporated herein by reference to Exhibit 10.5 to PostRock s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, filed on November 9, 2011).
21.1	List of Subsidiaries.

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Exhibit No.	Description
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.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF**	Taxonomy Extension Definition Linkbase Document.

* Incorporated by reference.
** Furnished not filed
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.