PostRock Energy Corp
Form 10-K
March 19, 2010

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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, 2009

Commission file number: 001-34635
PostRock Energy Corporation
(Exact Name of Registrant as Specified in Its Charter)

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**27-0981065** *(I.R.S. Employer Identification No.)*
210 Park Avenue, Suite 2750 **Oklahoma City, Oklahoma** *(Address of Principal Executive Offices)*	**73102** *(Zip Code)*

Registrant s telephone number, including area code:
(405) 600-7704

Securities Registered Pursuant to Section 12(b) of the Exchange Act:

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

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

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

PostRock Energy Corporation became a publicly traded corporation upon consummation of the recombination of Quest Resource Corporation, Quest Energy Partners, L.P. and Quest Midstream Partners, L.P. on March 5, 2010. Accordingly, the registrant did not have an aggregate market value of its common stock as of the last business day of June 30, 2009. As of March 8, 2010, there were 8,029,898 shares of common stock of PostRock Energy Corporation outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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PART I

ITEM 1. *BUSINESS.*

General

PostRock Energy Corporation (PostRock) is a Delaware corporation formed on July 1, 2009 for the purpose of effecting the recombination of Quest Resource Corporation (now named PostRock Energy Services Corporation) (QRCP), Quest Energy Partners, L.P. (now named PostRock MidContinent Production, LLC) (QELP) and Quest Midstream Partners, L.P. (now named PostRock Midstream, LLC) (QMLP). On July 2, 2009, PostRock, QRCP, QELP, QMLP and other parties thereto entered into a merger agreement pursuant to which QRCP, QELP and QMLP would recombine. The recombination was effected by forming a new publicly traded corporation, subsequently named PostRock, that, through a series of mergers and entity conversions, wholly owns all three entities. The recombination was completed on March 5, 2010. PostRock has no significant assets other than the stock or other voting securities of its subsidiaries. Immediately upon completion of the recombination, PostRock s equity was owned approximately 44% by former QMLP common unit holders, approximately 33% by former QELP common unitholders (other than QRCP), and approximately 23% by former QRCP stockholders.

Our principal executive offices are located at 210 Park Avenue, Suite 2750, Oklahoma City, Oklahoma 73102 and our telephone number is (405) 600-7704.

In this Annual Report on Form 10-K, unless the context requires otherwise, references to we, us and our with respect to periods before the completion of the recombination refer to the business and operations of QRCP, QELP and QMLP and their subsidiaries on a consolidated basis, and references to PostRock, we, us and our with respect to periods after the completion of the recombination refer to PostRock and its consolidated subsidiaries.

We are an integrated independent energy company engaged in the acquisition, exploration, development, production and transportation of oil and natural gas.

We divide our operations into two reportable business segments:

- Oil and natural gas production; and

- Natural gas pipelines, including transporting, gathering, treating and processing natural gas.

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

Our assets as of December 31, 2009 consisted of the following:

Cherokee Basin: Approximately 2,849 gross wells, which includes oil, natural gas and service wells, the development rights to approximately 516,184 net acres and approximately 2,173 miles of gas gathering pipeline in the Cherokee Basin. Of the 2,849 wells, there are approximately 189 wells that we believe to be capable of producing should gathering infrastructure be available. Of these 189 wells, approximately 100 wells are in an area where we have partially completed this infrastructure. Under Securities Exchange Commission (SEC) criteria, the estimated net proved reserves associated with these assets as of December 31, 2009 were 51.9 Bcfe. Based on NYMEX forward pricing as of February 1, 2010 and lower transportation costs as described under Oil and Gas Data Sensitivity of Reserves to Prices and Costs, the estimated net proved reserves were 192.2 Bcfe.

Appalachian Basin: Approximately 498 gross gas wells, the development rights to approximately 44,507 net acres and approximately 183 miles of gas gathering pipeline in the Appalachian Basin. Under SEC criteria, the estimated net proved reserves associated with these assets as of December 31, 2009 were 18.9 Bcfe. Based on NYMEX forward pricing as of February 1, 2010 and lower transportation costs as described under Oil and Gas Data Sensitivity of Reserves to Prices and Costs, the estimated net proved reserves were 26.3 Bcfe.

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Central Oklahoma: Approximately 65 gross wells, which includes oil, natural gas and service wells, and the development rights to approximately 1,480 net acres in Seminole County, Oklahoma. Under SEC criteria, the estimated net proved reserves associated with these Oklahoma properties as of December 31, 2009 were 3.9 Bcfe. Based on NYMEX forward pricing as of February 1, 2010 and lower transportation costs as described under Oil and Gas Data Sensitivity of Reserves to Prices and Costs, the estimated net proved reserves were 4.3 Bcfe.

Interstate Pipeline: An 1,120 mile interstate natural gas pipeline that transports natural gas from northern Oklahoma and western Kansas to the metropolitan Wichita and Kansas City markets.

Oil and Gas Production

Cherokee Basin. Our oil and gas production operations are primarily focused on the development of coal bed methane (CBM) in a 15-county region in southeastern Kansas and northeastern Oklahoma known as the Cherokee Basin. As of December 31, 2009, we had approximately 51.9 Bcfe of estimated net proved reserves in the Cherokee Basin. We operate approximately 99% of the existing Cherokee Basin wells and have an average net working interest of approximately 99% and an average net revenue interest of approximately 82% in those wells. We believe we are the largest producer of natural gas in the Cherokee Basin based on our average net daily production of 55.3 Mmcfe for the year ended December 31, 2009.

A typical Cherokee Basin CBM well has a predictable production profile and a standard economic life of approximately 15 years. As of December 31, 2009, we had the development rights to approximately 516,184 net acres throughout the Cherokee Basin, with 34.5% of those acres undeveloped, and were operating approximately 2,849 gross wells in the Cherokee Basin.

For 2010, we have budgeted approximately $6.0 million to complete and $5.5 million to connect 108 gross wells that were previously drilled but not completed and $2.7 million for land and equipment in the Cherokee Basin. We intend to fund these capital expenditures with available cash from operations after taking into account our debt service obligations and with the proceeds of additional equity capital issuances and borrowings, but there can be no assurance that we will be able to obtain the funds to achieve this plan.

Appalachian Basin. Our oil and gas production operations in the Appalachian Basin are primarily focused on the development of the Marcellus Shale. Our properties in this region were purchased in July 2008 through the acquisition of privately held PetroEdge Resources (WV) LLC (PetroEdge) for approximately $142 million in cash. We have identified, based on reserves as of December 31, 2009, approximately 25 gross proved undeveloped drilling locations and approximately 415 additional gross potential drilling locations in the Appalachian Basin, which consist of approximately 331 potential gross vertical well locations and approximately 84 potential gross horizontal well locations, including significant development opportunities for Devonian Sands and Brown Shales. These potential well locations are located within our acreage in West Virginia and New York and represent a significant part of our future long-term development drilling program. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, gas prices, costs and drilling results. The assignment of proved reserves to these locations is based on the twelve-month average price assumptions in our December 31, 2009 reserve report. In addition, no proved reserves are assigned to any of the approximately 415 Appalachian Basin potential drilling locations we have identified and therefore, there exists greater uncertainty with respect to the likelihood of drilling and completing successful commercial wells at these potential drilling locations. For 2010, we have budgeted approximately $20 million of net expenditures to drill and complete three vertical wells and six horizontal wells and $2.5 million on land, equipment and connections in the Appalachian Basin. There can be no assurance that we will be able to obtain the capital necessary to achieve this plan.

As of December 31, 2009, our properties in the Appalachian Basin consisted of:

- approximately 44,507 net acres of oil and natural gas producing properties with estimated proved reserves of 18.9 Bcfe, which are approximately 60% proved developed, and net production of approximately 2.9 Mmcfe/d; and

- Approximately 498 gross wells.

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We operate approximately 99% of the existing wells and have an average net working interest of approximately 93% and an average net revenue interest of approximately 74%. Our average net daily production in the Appalachian Basin was approximately 2.9 Mmcfe for 2009. Typical horizontal Marcellus Shale wells have a predictable production profile and an estimated productive life of approximately 50 years.

As of December 31, 2009, we owned the development rights to approximately 44,507 net acres throughout the Appalachian Basin, with 78% of that acreage undeveloped.

Central Oklahoma Oil Properties. As of December 31, 2009, we owned 65 gross wells, which include oil, natural gas and service wells, and the development rights to approximately 1,480 net acres in Central Oklahoma and our oil producing properties in Central Oklahoma had estimated net proved reserves, as of December 31, 2009, of 3.9 Bcfe, all of which were proved developed producing. During 2009, net production for our Central Oklahoma properties was approximately 148 Bbls/d. Our oil production operations in Central Oklahoma are expected to be primarily focused on the development of the Hunton Formation. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approval, oil prices, costs and drilling results.

Natural Gas Pipelines

Cherokee Basin. We own and operate a natural gas gathering pipeline network of approximately 2,173 miles that serves our acreage position in the Cherokee Basin. As of December 31, 2009, this system had a maximum daily throughput of approximately 85 Mmcf/d. We transport 99% of our Cherokee Basin gas production on our gas gathering pipeline network to interstate pipeline delivery points. As of December 31, 2009, we had an inventory of approximately 189 gross drilled CBM wells awaiting connection to our gas gathering system.

Appalachian Basin. We own and operate a gas gathering pipeline network of approximately 183 miles that serves our acreage position in the Appalachian Basin. The pipeline network delivers both to intrastate gathering and interstate pipeline delivery points. As of December 31, 2009, this system had a maximum daily throughput of approximately 18.0 Mmcf/d. All of our Appalachian Basin gas production is transported by this gas gathering pipeline network.

Interstate Pipeline System. Our interstate pipeline operations consist of a 1,120 mile interstate natural gas pipeline (the KPC Pipeline), which transports natural gas from northern Oklahoma and western Kansas to the metropolitan Wichita and Kansas City markets. The pipeline was purchased in November 2007 for approximately $133.7 million in cash, which was financed with funds from an equity issuance and from $58 million in borrowings. It is one of only three pipeline systems currently capable of delivering gas into the Kansas City metropolitan market. The KPC Pipeline includes three compressor stations with a total of 14,680 horsepower and has a throughput capacity of approximately 160 Mmcf/d. The Federal Energy Regulatory Commission (FERC) regulates the KPC Pipeline. The KPC Pipeline also has supply interconnections with pipelines owned and/or operated by Enogex Inc., Panhandle Eastern PipeLine Company and ANR Pipeline Company, which enable us to transport natural gas volumes sourced from the Anadarko and Arkoma Basins, as well as the western Kansas and Oklahoma panhandle producing regions.

Competitive Strengths

Dominant Position in the Cherokee Basin

We believe we are the largest producer of natural gas in the Cherokee Basin. During 2009, our net natural gas production in the basin was 55.3 Mmcf/d of natural gas. Our assets include a 99% working interest in 2,849 wells on 516,184 net acres in the Cherokee Basin. Based on NYMEX forward pricing as of February 1, 2010 and lower transportation costs as described under Oil and Gas Data Sensitivity of Reserves to Prices and Costs, we had 192.2 Bcfe of proved reserves in the Cherokee Basin as of December 31, 2009.

The Cherokee Basin is one of the largest CBM fields in the United States, generally characterized by having smaller wells with lower production per well and, thus, higher per unit costs than other conventional and unconventional natural gas plays. We believe that our size and relative position in the region is particularly

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valuable as we are able to maintain economies of scale that facilitate higher returns than those earned by our competitors and a stronger negotiating position on mineral leases, premium equipment and services. In addition, our dominant position makes us the logical consolidator of assets in the region.

Attractive Underlying Economics

Although the CBM wells in the Cherokee Basin are small by comparison to other conventional and non-conventional natural gas plays, we believe the underlying economics are consistent with other fields in the industry. We estimate that for 2010, our average cost for drilling and completing a well will be between $110,000 and $125,000 excluding the related pipeline infrastructure, or approximately $170,000 including the related pipeline infrastructure. We achieve these low costs because we drill to relatively shallow coal seams and can build a well in one to two days. We also own and operate fracture treatment equipment in the Cherokee Basin, which we believe allows us to complete our wells for a lower cost than our peers that rely upon third-party service providers. During a recent major drilling and completion program, which ended in the third quarter of 2008, we added net reserves of approximately 110 Mmcfe per well, resulting in a finding and development cost which we believe is competitive in the industry.

Integrated Business Model

Due to smaller well sizes in the Cherokee Basin, the rate of return we can achieve is highly sensitive to both our drilling costs and our operational costs. As a result, we have developed an integrated business model to drive our operations in an efficient and cost effective manner. In addition, due to its somewhat remote location and low capital expenditure requirements relative to more prolific basins, there are not currently enough service providers of sufficient scale and expertise to service the Cherokee Basin. To mitigate this, we have developed our own fleet of equipment and the expertise to use it in the field. In developing our assets, we tightly control the process of fracing and completing our wells by utilizing our two hydraulic frac units and our five cementing units. Once drilled, we are able to efficiently maintain our wells with our fleet of 24 workover units. Controlling these processes helps us to efficiently deploy our capital.

In 2008, which is the last year during which we actively developed the basin, we were able to drill 338 wells in eight months, roughly four months ahead of schedule and $10 million under budget. Utilizing our well servicing fleet and state of the art SCADA well pumping software, we have focused on keeping as many of our wells online as possible, and as of December 31, 2009, 99.7% of our producing wells were online producing CBM. Over the past three years, we have developed an artificial lift technology specifically suited for our wells in the Cherokee Basin that significantly improves well productivity. By reducing workover costs, decreasing offline wells, and increasing well productivity with artificial lift technology, we were able to reduce our total oil and natural gas production costs (excluding production and property taxes) from $1.58 per Mcfe in 2008 to $1.19 per Mcfe in 2009, a 25% decrease.

Extensive Midstream Infrastructure

Consistent with our goal to control costs through an integrated strategy, we have a well developed midstream infrastructure and a sophisticated gas marketing operation designed to reduce our transportation costs and to achieve the highest possible price for our gas. In the Cherokee Basin, we have 2,173 miles of gathering pipeline with 85 Mmcfe/d of throughput capacity. By owning this infrastructure, we reduce our costs by approximately 24% of market revenue, equivalent to the rate we charge third parties to use our pipelines. Today, we deliver 100% of our natural gas to the Southern Star pipeline and receive Southern Star s posted price plus a producing zone premium. We are in the process of connecting our gathering system to the KPC Pipeline, and when complete, we intend to market the KPC Pipeline as a header system, allowing greater opportunities to sell our natural gas to different markets, via the ANR, Panhandle Eastern, Kinder Morgan and Rockies Express pipelines. By creating access to premium markets in the upper Midwest and the Northeast, we believe connecting KPC to PostRock s existing production will allow us to receive a premium price for our gas or mitigate a regional differential we might otherwise be required to accept on Southern Star.

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Stable Base Production

The Cherokee Basin is a relatively mature field, and we believe our 2,849 wells are on a low and stable decline curve. Our daily net production in the third quarter of 2008 was 59 Mmcfe/d. We have not connected any new wells since then, and have elected to defer production on approximately 600 wells due to low natural gas prices. In the fourth quarter of 2009, our production had declined to 52 Mmcfe/d, which equates to an annualized decline rate of approximately 10%. In 2010, as we resume development activities, we expect that the decline will reverse and that our production will grow. Unlike companies that have a steeper decline rate and rely more heavily on development activities to replace their production, we believe we have a competitive advantage because we can hedge a significant portion of our stable production base, enabling us to lock in baseline cash flows to service our debt and further develop our assets.

Strong Commodity Hedging Position

As of December 31, 2009, we had 76% of our expected proved developed producing production for the next four years hedged at an average net price to us of $6.37 per Mmbtu. This hedge position includes both fixed price swaps based on NYMEX or Southern Star prices and basis differential swaps between NYMEX and various Southern Star delivery locations. This hedge position is expected to provide us approximately $317 million of revenues over the next four years, even if the remainder of our production is sold at break-even gas prices.

Valuable Appalachian Acreage Position

In July 2008, we entered the Appalachian Basin through our purchase of PetroEdge Resources. As a result of this acquisition, we now own a small amount of existing conventional production and 44,507 Marcellus Shale acres, including 8,514 acres in Wetzel and Lewis Counties in West Virginia. We have chosen to focus on areas with existing infrastructure, substantially lowering the cost of developing these assets. We have identified 84 horizontal well locations on our acreage in Wetzel and Lewis counties. Based on NYMEX forward pricing as of February 1, 2010 and lower transportation costs as described under Oil and Gas Data Sensitivity of Reserves to Prices and Costs, we had 26.3 Bcfe of proved reserves in the Appalachian Basin.

Business Strategies

Improve Financial Flexibility

We are focused on improving our financial flexibility by strengthening our leverage profile and enhancing liquidity. We are committed to issuing equity for the purpose of both repaying debt and acquiring additional producing acreage in the Cherokee Basin. We also intend to redeploy our free cash flow from operations into our assets to help grow our reserves and production, which will allow us to further improve our leverage profile over time.

Continued Development of the Cherokee Basin Through Strict and Systematic Operational Controls

As we develop our economical drilling locations in the Cherokee Basin, we will continue to utilize our integrated model to drive efficiency and minimize costs. We will focus our drilling, completion, maintenance, and marketing operations on industry best practices and continued technological enhancements to maximize our return on assets and capital deployed.

Actively Manage Price Exposure through Midstream Strategy and Hedging

We intend to actively manage our exposure to natural gas prices and basis differential in the MidContinent region by connecting our gathering system to the KPC Pipeline. By creating access to premium markets in the upper Midwest and the Northeast, we believe connecting KPC to PostRock s existing production will allow us to receive a premium price for our gas or mitigate a regional differential we might otherwise receive on Southern Star. Once this connection is complete, we expect to be in a position to significantly expand the markets where our gas can be sold, thus reducing our exposure to the historically volatile basis differentials between NYMEX and the Southern Star delivery points. Further, we intend to continue to use both NYMEX swaps and basis swaps to protect the price at which we sell gas. By maximizing the revenue we earn for our gas, and locking in attractive prices when available, we believe we can stabilize and significantly increase our cash flow generation.

Consolidate the Cherokee Basin

To further enhance our economies of scale, we intend to actively pursue acquisitions in the Cherokee Basin. Consistent with our strategy to improve our financial flexibility, we intend to make acquisitions utilizing our equity. We believe our integrated model, midstream footprint and gas marketing capabilities are unique to the Cherokee Basin, and make our competitors gas more valuable under our control. We believe that we offer a compelling value proposition for other producers in the region.

Develop Appalachian Assets

We have approximately 25 gross proved undeveloped drilling locations and an additional 415 potential locations on approximately 45,000 acres in the Marcellus Shale. We intend to prudently develop this acreage position by redeploying cash flow generated in the Cherokee Basin. As we are focused on locations in areas with existing infrastructure, we expect our development plan to have a near-term material impact on our proved reserves and production. We believe investing in this area is the most expedient way for us to improve our financial flexibility and return on capital.

Description of Our Exploration and Production Properties and Projects

Cherokee Basin

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

The Cherokee Basin is part of the Western Interior Coal Region of the central United States. The coal seams we target for development are found at depths of 300 to 1,400 feet. The principal formations we target include the Mulky, Weir-Pittsburgh and the Riverton. These coal seams are blanket type deposits, which extend across large areas of the basin. Each of these seams generally range from two to five feet thick. Additional minor coal seams such as the Summit, Bevier, Fleming and Rowe are found at varying locations throughout the basin. These seams range in thickness from one to two feet.

The rock containing conventional gas, referred to as source rock, is usually different from reservoir rock, which is the rock through which the conventional gas is produced, while in CBM, 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 allows large quantities of gas to be stored at relatively low pressures. A 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 depressuring before desorption can occur and the methane begins to flow at commercial rates. Our Cherokee Basin CBM properties typically dewater for a period of 12 months before peak production rates are achieved.

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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. Once coal bed methane has been produced, it is gathered, transported, marketed and priced in the same manner as conventional gas. The CBM produced from our Cherokee Basin properties has an Mmbtu content of approximately 970 Mmbtu, compared to conventional natural gas hydrocarbon production which can typically vary from 1,050-1,300 Mmbtus.

The content of gas within a coal seam is measured through gas desorption testing. The ability to flow gas and water to the wellbore in a CBM well is determined by the fracture or cleat network in the coal. While, at shallow depths of less than 500 feet, these fractures are sometimes open enough to produce the fluids naturally, at greater depths the networks are progressively squeezed shut, reducing the ability to flow. 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 and a slurry of fluid and sand is pumped into the fractures so that the fractures remain open after the release of pressure, thereby enhancing the flow of both water and gas to allow the economic production of gas.

Cherokee Basin Projects

We intend to develop our CBM reserves in the Cherokee Basin on both 160-acre and 80-acre spacing. Our wells generally reach total depth in 1.5 days. During 2009, we drilled and completed one well. During a recent major drilling and completion program, which ended in the third quarter of 2008, our cost to drill and complete a well, excluding the related pipeline infrastructure, was approximately $125,000. We estimate that for 2010, our average cost for drilling and completing a well will be between $110,000 and $125,000 excluding the related pipeline infrastructure, or approximately $170,000 including the related pipeline infrastructure. For 2010, in the Cherokee Basin, we have budgeted approximately $6.0 million to complete and $5.5 million to connect 108 gross wells that were previously drilled but not completed. The majority of these new wells will be completed on locations that are classified as containing proved reserves in the December 31, 2009 reserve report. In 2010, we have budgeted an additional $2.7 million for land and equipment. However, we intend to fund these capital expenditures only to the extent that we have available cash from operations after taking into account our debt service and other obligations, and with the proceeds of equity capital issuances and borrowings. We can give no assurance that any such funds will be available.

We perforate and frac the multiple coal seams present in each well. Our typical Cherokee Basin multi-seam CBM well has net reserves of approximately 110 Mmcf. Our general production profile for a CBM well averages an initial production rate of 5-10 Mcf/d (net), steadily rising for the first twelve months while water is pumped off and the formation pressure is lowered. A period of relatively flat production of 50-55 Mcf/d (net) follows the initial dewatering period for approximately twelve months. Thereafter, production begins to decline. The standard economic life is approximately 15 years. Our completed wells rely on very basic industry technology.

Our development activities in the Cherokee Basin encompass a program to recomplete CBM wells that produce from a single coal seam to wells that produce from multiple coal seams. We believe we have approximately 200 additional wellbores that are candidates for recompletion to multi-seam producers. The recompletion strategy is to add four to five additional pay zones to each wellbore, in a two-stage process at an average cost of approximately $28,000 to $36,000 per well. Adding new zones to an existing well has a brief negative effect on production by first taking the well offline to perform the work and then by introducing a second dewatering phase of the newly completed formations. However, in the long term, we believe the impact of the multi-seam recompletions will be positive as a result of an increase in the rate of production, a higher return on capital, and an increase in the ultimate recoverable reserves available per well.

Appalachian Basin

The Appalachian Basin is one of the largest and oldest producing basins within the United States. It is a northeast to southwest trending, elongated basin that deepens with thicker sections to the east. This basin takes in southern New York, Pennsylvania, eastern Ohio, extreme western Maryland, West Virginia, Kentucky, extreme western/northwestern Virginia, and portions of Tennessee. The basin is bounded on the east by a line of metamorphic rocks known as the Blue Ridge province which is thrusted to the west over the basin margin. Most prospective sedimentary rocks containing hydrocarbons are found at depths of approximately 1,000-9,000 feet with shallowest production in areas where oil and gas are seeping from the outcrop. Most productive horizons are found in sedimentary strata of Pennsylvanian, Mississippian, Devonian, Silurian, and Ordovician age. The Appalachian Basin has been an active area for oil and gas exploration, production and marketing since the mid-1800s. Although deeper zones are of interest, the main exploration and development targets are the Mississippian and Devonian sections.

Our main area of interest in the Appalachian Basin is within West Virginia, where there are producing formations at depths of 1,500 feet to approximately 8,000 feet. Specifically, our main production targets 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 members, Rhinestreet Shales). Although deeper targets are of interest (Onondaga and Oriskany), they are of lesser importance. The Mississippian formations are a conventional petroleum reservoir with the Devonian sections being a non-conventional energy resource.

The method for exploring and drilling these targets is different in several aspects. The Mississippian and Upper Devonian sections are explored through vertical drilling. The lower Marcellus section is explored by both vertical and horizontal drilling. The Mississippian section is identified by distinct sand and limestone zones with conventional porosity and permeability. Depths range from 1,000-2,500 feet deep. The Upper Devonian sands, siltstones, and shales are identified as multiple stacked pay lenses with depths ranging from 2,500-7,000 feet deep. The Marcellus Shale ranges in depth from 5,900 feet in portions of West Virginia to 7,100 feet in other portions of West Virginia. In certain areas of our development rights, vertical wells are drilled with combination completions in the Mississippian, Upper Devonian, and the Marcellus. Occasionally, vertical wells might only complete a single section of the three prospective pay intervals.

Our technical team has extensive experience in vertical and horizontal exploration, development and production. We have identified areas within the Appalachian Basin that we believe are prospective for both vertical and horizontal targets. As of December 31, 2009, we had development rights to acreage in approximately 18 counties within the Appalachian Basin. We have identified, based on reserves as of December 31, 2009, approximately 25 gross proved undeveloped drilling locations. Certain counties are vertical drilling targets for development and other counties are horizontal development targets. We believe there are over 331 gross vertical locations that would include potential production from one or all three of the Mississippian, Upper Devonian Sands, and Siltstones. We believe there are approximately 84 gross horizontal locations that would include the primary target for the Marcellus formation. In 2009, we completed two horizontal wells located in Wetzel County, West Virginia. This county in particular, along with Lewis County, West Virginia, is prospective for horizontal drilling in the Marcellus. Depths to the Marcellus in Lewis County and Wetzel County range from 6,300 feet to 7,200 feet. The thickness of the Marcellus in these counties ranges from just over 50 feet thick to over 90 feet thick.

Appalachian Basin Projects

As of December 31, 2009, our Appalachian Basin estimated net proved reserves totaled 18.9 Bcfe and were producing approximately 2.9 Mmcfe/d. During 2009, we drilled and completed one gross vertical well and completed two gross horizontal wells in Wetzel County, West Virginia, all of which are currently producing. The two horizontal wells were drilled and completed at a gross cost of $6.4 million and $5.3 million, respectively, while the vertical well was drilled and completed at a cost of $1.1 million. The two horizontal wells and one vertical well had initial production rates of 2.7 Mmcf/d, 1.3 Mmcf/d and 1.8 Mmcf/d, which have since declined to average production rates of 1.3 Mmcf/d, 0.2 Mmcf/d and 0.5 Mmcf/d, respectively. We have a net working interest of 50% in these three wells.

For 2010, we have budgeted net capital expenditures of approximately $20 million to drill and complete three vertical wells and six horizontal wells and approximately $2.5 million for land, equipment and connections in the Appalachian Basin. Each well will be drilled on a location that is classified as containing

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proved reserves in our December 31, 2009 reserve report. The expenditure of these funds is subject to capital being available.

Central Oklahoma Oil Properties

Our primary Oklahoma oil producing properties are located in Seminole and Pottawatomie counties located in south central Oklahoma. Oil was discovered in this area in 1926. Primary oil productive formations have included Hunton, Misener, Sylvan, Viola, Wilcox, Simpson and Oil Creek. Since discovery, these properties have undergone several phases of development. The Hunton Limestone is the main producing formation in the area. The Hunton formation is approximately 4100 feet in depth and ranges from 25 to 120 feet in thickness across the properties. Oil is produced from zones of lenticular porosity development. Primary oil recovery is limited by the discontinuous nature of the porosity development and early attempts to waterflood the Hunton had generally poor results. Today, high water cut Hunton oil is produced via numerous vertical production wells. Oil and produced formation water are separated at the surface and the produced water disposed, on-site, primarily into the underlying Wilcox sands. We believe that significant Hunton oil reserves remain trapped in the discontinuous porosity zones and plan to further develop this reservoir using horizontal drilling and production technologies when capital is available.

Oil and Gas Data

Reserves categories

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience 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 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. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. Although probable and possible reserve locations are found by stepping out from proved reserve locations, estimates of probable and possible reserves are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by us.

Estimated Reserves

The following table presents our estimated net proved, probable and possible oil and gas reserves relating to our oil and natural gas properties as of December 31, 2009 based on our reserve reports as of such date. The data was prepared by the independent petroleum engineering firm Cawley, Gillespie & Associates, Inc. Reserves at December 31, 2009 were determined using the unweighted arithmetic average of the first day of the month price for each month from January through December 2009, which we refer to as the 12-month average price as of December 31, 2009, of $61.18 per barrel of oil and $3.87 per Mmbtu of gas.

	Natural Gas (Bcf)	**Oil (MMbbl)**	**Total (Bcfe)(1)**
Proved reserves			
Developed	62.1	0.78	66.8
Undeveloped	7.7	0.05	8.0

Total proved reserves	69.8	0.83	74.8
Total probable reserves	4.5		4.5
Total possible reserves	9.1		9.1

(1) Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.

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Proved Undeveloped Reserves

At December 31, 2009, we had 7,971 Mmcfe of proved undeveloped reserves. During 2009, due to liquidity constraints, we did not convert any reserves from proved undeveloped to proved developed. Proved undeveloped reserves decreased from 2008 due to the significant decrease in prices used to determine our reserves. We do not have proved undeveloped reserves that will require more than five years to develop.

Sensitivity of Reserves to Prices and Costs

Fluctuations in the prices and costs used in the estimation of reserves can cause significant variations in the resulting reserve calculation. We believe it would be meaningful to consider different price and cost sensitivities to the reserve calculation presented above, particularly with respect to transportation costs following consummation of the recombination. The following table represents reserve amounts as of December 31, 2009 under three different pricing and cost scenarios explained below. The reserves presented under the alternative price and cost assumptions have been prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers.

Sensitivity of Reserves to Prices and Costs
As of December 31, 2009

	SEC Modernization Methodology(1)			**Recombined Methodology(2)**			**Recombined NYMEX Methodology(3)**		
	Gas (Bcf)	**Oil (MMbbl)**	**Total (Bcfe)**	**Gas (Bcf)**	**Oil (MMbbl)**	**Total (Bcfe)**	**Gas (Bcf)**	**Oil (MMbbl)**	**Total (Bcfe)**
Proved reserves									
Developed	62.1	0.78	66.8	96.5	0.78	101.2	158.9	0.87	164.1
Undeveloped	7.7	0.05	8.0	8.8	0.05	9.1	58.4	0.05	58.7
Total proved reserves	69.8	0.83	74.8	105.3	0.83	110.3	217.3	0.92	222.8
Total probable reserves	4.5		4.5	31.7	0.33	33.7	57.4	0.33	59.4
Total possible reserves	9.1		9.1	9.1		9.1	94.8	0.06	95.2

	SEC Modernization Methodology(1)	**Recombined Methodology(2)**	**Recombined NYMEX Methodology(3)**
		(in thousands)	
PV-10 value(4):			
Proved reserves	$ 50,559	$ 99,901	$ 431,901
Probable reserves	435	2,120	63,437
Possible reserves	139	139	75,996

(1) Amounts determined based on the recently adopted SEC final rule Modernization of Gas and Oil Accounting . The prices used in this calculation equal the 12-month average price as of December 31, 2009 used in the table above under Estimated Reserves. The transportation cost on our Cherokee Basin production was $1.70 per Mcf, which is based on the gathering rate charged under the midstream services and gas dedication agreement between Bluestem Pipeline, LLC and QELP in effect during 2009.

(2) The prices used in this calculation are the same as those described in footnote 1. This scenario assumes that the midstream services and gas dedication agreement, which after the recombination is an intercompany agreement, is no longer in effect and therefore utilizes our current estimate of direct pipeline operating expense for our natural gas gathering pipeline system of $0.80 per Mcf.

(3) Amounts determined based on the publicly traded NYMEX 2010 to 2015 natural gas and oil forward curve as of February 1, 2010. The average 5 year forward price for natural gas was $6.38 per Mmbtu and the average 5 year forward price for crude oil was $82.75 per barrel. This scenario assumes that the midstream services and gas dedication agreement is no longer in effect and therefore utilizes our current estimate of direct pipeline operating expense for our natural gas gathering pipeline system of $0.80 per Mcf.

(4) The PV-10 value of our reserves is a non-GAAP financial measure. PV-10 value is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable financial measure under generally accepted accounting principles. PV-10 value is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 value is equal to the standardized measure of discounted future net cash flows at a specified date before deducting future income taxes, discounted at 10%. Discounted future net cash flows are based on assumptions of future prices, future production costs and future development costs. However, as a result of our significant net operating loss carryfowards, we do not expect to incur future income tax liabilities for the foreseeable future and therefore have an effective future income tax rate of zero. As such, there is no difference between the standardized measure and the PV-10 value of our reserves under the different methodologies. We believe that the presentation of the PV-10 value is relevant and useful to investors because it presents the discounted future net cash flows attributable to our reserves, and it is a useful measure of evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. However, PV-10 value is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 value measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves as of the specified dates.

The reserve data above represents estimates only. Reserve estimates are imprecise and may change as additional information becomes available. Furthermore, estimates of natural gas and oil reserves are projections based on geoscience and engineering data. There are uncertainties inherent in the interpretation of these data as well as the projection of future rates of production and the timing of development expenditures. Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and 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.

In addition to proved reserves, which are those quantities of natural gas and oil that can be estimated with reasonable certainty to be economically producible within the time period provided by applicable SEC rules, we disclose in this annual report our probable and possible reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves include additional reserves that are less certain to be recovered than probable reserves. These estimates of probable and possible reserves are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by us.

Internal Controls

A significant component of our internal controls in our reserve estimation effort is our practice of using an independent third-party reserve engineering firm to prepare 100% of our year-end proved reserves and, for 2009, our probable and possible reserves. The qualifications of this firm are discussed below under Independence and Qualifications of Reserve Preparer. While we do not have a formal review process, reserves are presented to management and the board of directors for review and approval.

Our internal reserve engineers report to our Director of Reservoir Engineering and Geology, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides appropriate data to our independent third party reserve engineers to estimate our year-end reserves. Our internal reserve engineer staff consists of four degreed petroleum/mechanical/chemical engineers, with between four and 28 years reservoir engineering experiences, and between three months and three years of experience managing our reserves. All of our internal reserve engineers are members of the Society of Petroleum Engineers.

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Production Volumes, Sales Prices and Production Costs

The following table sets forth information regarding our oil and natural gas properties. The oil and gas 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	**2008**	**2007**
Net Production:			
Gas (Bcf)	21.24	21.33	16.98
Oil (Bbls)	83,015	69,812	7,070
Gas equivalent (Bcfe)	21.73	21.75	17.02
Oil and Gas Sales ($ in thousands):			
Gas sales	$ 75,106	$ 156,051	$ 104,853
Oil sales	4,787	6,448	432
Total oil and gas sales	$ 79,893	$ 162,499	$ 105,285
Avg Sales Price (unhedged):			
Gas ($ per Mcf)	$ 3.54	$ 7.32	$ 6.18
Oil ($ per Bbl)	$ 57.66	$ 92.36	$ 61.10
Gas equivalent ($ per Mcfe)	$ 3.68	$ 7.47	$ 6.19
Avg Sales Price (hedged)(1):			
Gas ($ per Mcf)	$ 8.11	$ 7.02	$ 6.60
Oil ($ per Bbl)	$ 69.93	$ 90.44	$ 61.10
Gas equivalent ($ per Mcfe)	$ 8.19	$ 7.18	$ 6.61
Oil and gas operating expenses ($ per Mcfe):			
Production costs, excluding production and property taxes	$ 1.19	$ 1.58	$ 1.71
Production and property taxes	$ 0.35	$ 0.45	$ 0.42
Net Revenue ($ per Mcfe)	$ 2.14	$ 5.44	$ 4.06

(1) Data includes the effects of our commodity derivative contracts that do not qualify for hedge accounting. The following table summarizes the realized gains (losses) by commodity type by period:

	Year Ended December 31,		
	2009	**2008**	**2007**
Realized gain (loss) on hedges			
Gas Hedges	$ 97,130	$ (6,254)	$ 7,279
Oil Hedges	$ 1,018	$ (134)	
Total	$ 98,148	$ (6,388)	$ 7,279

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

	Year Ended December 31, 2009		
	Natural Gas (Bcfe)	Oil (Bbls)	Total (Bcfe)
Production:			
Cherokee Basin	20.2	9,474	20.26
Appalachia	0.96	18,432	1.06
Central Oklahoma and other	0.08	55,109	0.41

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	Natural Gas (per Mcfe)	Oil (per Bbl)	Total (per Mcfe)
Average Sales Prices			
Cherokee Basin	$ 3.31	$ 54.66	$ 3.32
Appalachia	8.30	51.90	8.34
Central Oklahoma and other	4.30	60.10	8.91

	Year Ended December 31, 2009
Production Costs (per Mcfe):	
Cherokee Basin	$ 1.04
Appalachia	3.11
Central Oklahoma and other	3.67

Producing Wells and Acreage

The following tables set forth information regarding our ownership of producing wells and total acres as of December 31, 2009, 2008 and 2007. Of our nonproducing wells, we cannot determine, without unreasonable effort or expense, the number of wells mechanically capable of producing as of such dates.

	Producing Wells					
	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
December 31, 2007	2,225	2,218.2	29	28.1	2,254	2,246.3
December 31, 2008(1)	2,873	2,825.0	82	80.2	2,955	2,905.2
December 31, 2009(2)	2,442	2,397.8	48	43.7	2,490	2,441.6

(1) Increase includes approximately 500 gross Appalachian Basin wells acquired in the acquisition of PetroEdge Resources (WV) LLC in July 2008, or the PetroEdge acquisition, and 55 gross wells acquired in Seminole County, Oklahoma.

(2) Decrease from 2008 is due primarily to shutting in wells as a result of low natural gas prices.

	Acreage					
	Producing(1)		Nonproducing		Total	
	Gross	Net	Gross	Net	Gross	Net
December 31, 2007(2)	403,048	393,480	204,104	187,524	607,152	581,004
December 31, 2008(3)(4)	464,702	446,537	208,224	180,707	672,926	627,244
December 31, 2009(5)(6)	446,129	432,008	139,018	130,161	585,147	562,169

(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 Mexico, Texas and Pennsylvania.

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

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

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

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

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As of December 31, 2009, in the Cherokee Basin, we had 338,235 net developed acres and 177,946 net undeveloped acres. As of December 31, 2009, in the Appalachian Basin, we had 9,771 net developed acres and 34,736 net undeveloped acres. 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

The table below sets forth the number of wells completed at any time during the period, regardless of when drilling was initiated. Our drilling, recompletion, abandonment, and acquisition activities for the periods indicated are shown below (this information is inclusive of all basins and areas):

	Year Ended December 31, 2009		**Year Ended December 31, 2008**		**Year Ended December 31, 2007**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells drilled:						
Productive			1	1		
Dry	1	1	1	1		
Development wells drilled:						
Productive	4	2.5	339	338	572	572
Dry						
Wells plugged and abandoned	11	11	17	17		
Wells acquired capable of production(1)	9	1.6	551	514.5		
Net increase in capable wells	3	(5.9)	875	837.5	572	572
Recompletion of old wells:						
Capable of production			14	14	50	49

(1) Includes 53.5 net and 55 gross oil wells capable of production acquired in Seminole County, Oklahoma in February 2008. The remainder of the 2008 acquired wells were acquired as part of the PetroEdge acquisition.

Independence and Qualifications of Reserve Preparer

We engaged Cawley, Gillespie & Associates, Inc., third-party reserve engineers, to prepare our reserves as of December 31, 2009, 2008 and 2007. The technical person responsible for our reserve estimates at Cawley, Gillespie & Associates, Inc. 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. Cawley, Gillespie & Associates, Inc. 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.

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

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infrastructure for new wells (such as electric service, salt water disposal facilities, and gas feeder lines). The primary equipment categories owned by us are trucks, well service rigs, stimulation assets and construction equipment. We utilize third-party contractors on an as needed basis 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 are also able to realize significant cost savings because we can reduce delays in executing our plan of development, avoid paying price markups and are able to purchase our own supplies at bulk discounts. 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 well site construction. We have our own fleet of 24 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.

Oil and Gas Leases and Development Rights

As of December 31, 2009, we had approximately 4,200 leases covering approximately 562,169 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 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 oil and gas operators. In order to gain the right to drill these leases, we may purchase leases from other oil and gas operators. In some cases, the assignor of such leases will reserve an overriding royalty interest, ranging from 3.125% to 16.5% which further reduces the net revenue interest available to us to between 64.75% and 84.375%.

As of December 31, 2009, approximately 77% of our oil and gas leases were held by production, which means that for as long as our wells continue to produce oil or gas, we will continue to own those respective leases.

In the Cherokee Basin, as of December 31, 2009, we held oil and gas leases on approximately 516,184 net acres, of which 124,180 net acres (24%) 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 75,621 net acres are scheduled to expire before December 31, 2010. If these leases expire and are not renewed, we will lose the right to develop the related properties.

We hold oil and gas leases and development rights, by virtue of farm-out agreements or similar mechanisms, on 29,877 net acres in the Appalachian Basin 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. We are required to drill three gross gas wells by April 30, 2010 in order to maintain approximately 2,000 net acres. We must also drill an additional three gross gas wells by December 31, 2010 to maintain approximately an additional 6,000 net acres. Furthermore, we are currently required to drill an additional four gross wells in order to maintain 1,605 net acres in New York. The exact deadline for the drilling of these four wells is currently unclear, due to permitting delays caused by an environmental impact review being conducted by the state of New York. We may not be able to meet the drilling and payment obligations to earn or maintain all of this leasehold acreage.

Gas Gathering Systems

Our Cherokee Basin gas gathering system includes approximately 2,173 miles of low pressure gas gathering pipeline network. The system provides a market outlet for natural gas in a region of approximately 1,000 square miles in size and has connections to both intrastate and interstate delivery pipelines. We believe it is the largest gathering system in the Cherokee Basin with a current throughput capacity of approximately 85 Mmcf/d and delivers virtually all its gathered gas into Southern Star Central Gas Pipeline at multiple interconnects. This gathering system includes 77 field compression units comprising approximately 48,000 horsepower of compression in the field (most of which are currently rented) as well as five CO_2 amine treating facilities.

We gather on our gas gathering system substantially all of the natural gas we produce in the Cherokee Basin in addition to some natural gas produced by other companies. The pipeline network is a critical asset for our future growth in the Cherokee Basin because natural gas gathering pipelines are a costly component of the infrastructure required for natural gas production and such pipelines are not easily constructed.

During 2009, we connected two wells. We estimate that our cost for pipeline infrastructure in 2010 will be approximately $5.5 million to connect 108 gross wells in the Cherokee Basin that were previously drilled but not completed, if the outlook for commodity prices remains at the level where we believe the connection of these wells is justified and if we have available capital.

We also own and operate a gas gathering pipeline network of approximately 183 miles that serves our acreage position in the Appalachian Basin. The pipeline delivers both to intrastate gathering and interstate pipeline delivery points. As of December 31, 2009, this system has a maximum daily throughput of approximately 18 Mmcf/d. All of our Appalachian gas production is transported by this gas gathering pipeline network.

The table below sets forth the natural gas volumes gathered on our gas gathering pipeline networks during the years ended December 31, 2009 and 2008.

	Year Ended December 31,	
	2009	**2008**
Pipeline Natural Gas Vols (Mmcf):		
Cherokee Basin	26,083	27,093
Appalachian Basin	956	476

Third-Party Gas Gathering

For services rendered to third parties, we retain a portion of the gas volumes sold. For 2009, approximately 6% of the gas transported on our natural gas gathering pipeline systems was for third parties.

Interstate Natural Gas Pipeline

The KPC Pipeline is an interstate natural gas transportation pipeline located in Kansas, Oklahoma and Missouri that we acquired in November 2007. The pipeline was assembled in the mid-1980 s from various crude oil transportation pipelines. Over the years, the KPC Pipeline has been reliant on Kansas Gas Services (KGS) and Missouri Gas Energy (MGE) for the majority of its revenue from firm capacity transportation contracts. The firm capacity transportation contract with MGE for approximately 46,000 Dth/d expired on October 31, 2009 and was not renegotiated or renewed. The pipeline has an approximate capacity of up to 160 MMcf/d. The KPC Pipeline is underutilized in terms of throughput and its prior owners did little to diversify markets. We are seeking to significantly increase opportunities to grow throughput to maximize the value of the KPC Pipeline, such as creating additional service options for both gas suppliers and consumers and developing additional pipeline interconnects to provide customers greater optionality for gas supply and market. During the fourth quarter of 2009, the KPC Pipeline added five new customers with various business services. In early October 2009, the FERC approved KPC s request to provide Park and Loan services on the KPC Pipeline. This creates a new income opportunity for the KPC Pipeline as well as provides a value-adding service for customers as they balance gas supply and demand. We will continue to evaluate other opportunities and additional services, each intended to create value for the customer while providing incremental revenue for the KPC Pipeline.

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The management team responsible for the KPC Pipeline has short, intermediate and long-term strategies in place to stabilize and grow the KPC Pipeline asset base and cash flows. Many of these strategies are being pursued with a limited number already in implementation. It may take several years to reach its ultimate potential, which may never be achieved. Management believes that the KPC Pipeline is a valuable asset with significant potential.

Impairment of Gas Gathering and Interstate Pipelines

Certain events during the fourth quarter of 2009 indicated our pipeline assets and intangibles could be impaired. We were unable to negotiate a new contract with one of our major customers for the KPC Pipeline, MGE. Our existing contract with MGE expired in October 2009, although prior to the expiration we believed that the contract could be extended or renegotiated with MGE or replaced by another customer. In addition, while we were successful in negotiating amendments to our credit facilities in December 2009, the amended credit facilities imposed limits on our capital expenditures and consequently on our ability to further develop acreage in the Cherokee Basin, the geographic region served by our gathering system. This reduced the future projected revenues of the gathering system.

Based on our analysis, we determined that the carrying value of our pipeline assets exceeded their fair values by approximately $164.7 million and recorded an impairment for such amount in the fourth quarter of 2009. In addition, we determined that our customer-related contracts, held by KPC and presented as intangible assets on the balance sheet, were also impaired. We recognized an impairment of $1.0 million on our intangible assets. No such impairment was required at December 31, 2008.

Marketing and Major Customers

Exploration and Production

In the Cherokee Basin for 2009, substantially all of our gas production was sold to ONEOK Energy Marketing and Trading Company (ONEOK). The ONEOK sales agreement is a monthly evergreen agreement, cancellable by either party. In the fourth quarter of 2009, we diversified our gas sales in the Cherokee Basin between six markets, including sales directly to end use customers. We will seek to continue to diversify our sales portfolio balancing price, credit risk and volume risk. These efforts also are expected to reduce marketing risk and provide competition to optimize the price we receive for our production.

During 2009, we sold 100% of our oil production in the Cherokee Basin to Coffeyville Refining, 100% of our oil production in Central Oklahoma to Sunoco Partners Marketing & Terminals L.P. and 100% of our oil production in the Appalachian Basin to Appalachian Oil Purchasers, a division of Clearfield Energy.

Approximately 86% of our 2009 Appalachian Basin natural gas production was sold to Dominion Field Services under a mix of fixed price and index based sales contracts and a market sensitive contract. Another 7% was sold to Hess Corporation under a mix of fixed price and index based sales contracts. The remainder of the Appalachian natural gas production was sold to various purchasers under market sensitive pricing arrangements. None of these remaining sales exceeded 3% of total Appalachian Basin natural gas production. Due to the history of problematic Northeastern pipeline constraints, we have secured a firm transportation agreement for a portion of our gas to ensure uninterrupted deliveries of our natural gas production.

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

Interstate Pipeline

Historically, the two primary shippers on the KPC Pipeline were Kansas Gas Service and Missouri Gas Energy. For 2009, approximately 59% and 32% of the revenue from the KPC Pipeline were from firm capacity

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transportation contracts with KGS and MGE, respectively. KGS, a division of ONEOK, Inc., is the local distribution company in Kansas for Kansas City and Wichita as well as a number of other municipalities. MGE, a division of Southern Union Company, is a natural gas distribution company that serves over one-half million customers in 155 western Missouri communities. The firm capacity transportation contract with MGE for approximately 46,000 Dth/d expired on October 31, 2009 and was not renegotiated or renewed. KGS s contracts for firm capacity on the KPC Pipeline include contracts for the following capacities and expiration dates:

Capacity	Time Period
57,568 Dth/d	November 1, 2009 through October 31, 2012
44,636 Dth/d(*)	November 1, 2009 through October 31, 2015
43,171 Dth/day(*)	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

(*) yearly average, some volumes adjusted for seasonal needs.

Commodity Derivative Activities

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 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 contracts priced at a fixed discount to NYMEX oil prices. Due to the historical volatility of oil and natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of prices we receive for the sale of our future production. 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 oil or natural gas prices. As a result of rising commodity prices, we may recognize additional charges to future periods. We hold derivative contracts based on Southern Star and NYMEX oil and natural gas prices, and we have fixed price sales contracts with certain customers in the Appalachian Basin. These derivative contracts and fixed price contracts mitigate our risk of fluctuating commodity prices but do not eliminate the potential effects of changing commodity prices. We limit our exposure to basis differential risk by generally entering into derivative contracts that are based on the same indices on which the underlying sales contracts are based or by entering into basis swaps for the same volume of hedges that settle based on NYMEX prices.

As of December 31, 2009, we held derivative contracts covering approximately 49.7 Bcf of natural gas through 2013 and 30,000 Bbls of oil through 2010. Approximately 12.5 Bcf of our Cherokee Basin natural gas production is hedged utilizing contracts that settle on Southern Star prices at a weighted average price of $6.24/Mmbtu for 2010, and approximately 7.0 Bcf of our Cherokee Basin natural gas production is hedged utilizing contracts that settle on Southern Star prices at a weighted average price of $6.51/Mmbtu for 2011 through 2012. Approximately 3.6 Bcf of our Cherokee Basin natural gas production is hedged utilizing contracts that settle on NYMEX prices at a weighted average price of $6.31/Mmbtu for 2010, and approximately 26.6 Bcf of our Cherokee Basin natural gas production is hedged utilizing contracts that settle on NYMEX prices at a weighted average price of $7.18/Mmbtu for 2011 through 2013. Our fixed price contracts hedge approximately 0.12 Bcf of our Appalachian Basin natural gas production at a weighted average price of $8.76/Mmbtu for the first quarter of 2010. We also held basis swaps covering approximately 3.6 Bcf of our Cherokee Basin natural gas production that settle on the difference between NYMEX and Southern Star prices at a weighted average difference of $0.63/Mmbtu for 2010 and approximately 26.6 Bcf of our Cherokee Basin natural gas production at a weighted average difference of $0.69 for 2011 through 2013.

As of December 31, 2009, approximately 30,000 Bbls of our Central Oklahoma crude oil production is hedged utilizing NYMEX contracts at a weighted average price of $87.50/Bbl for 2010. For more information on our derivative contracts, see Part II, Item 7A Quantitative and Qualitative Disclosures About Market Risk of this Annual Report on Form 10-K.

Competition

Exploration and Production

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

Gas Gathering

Our gas gathering systems experience minimal competition because approximately 94% of these systems throughput is attributable to our production.

Interstate Pipelines

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

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating hazards and risks that could result in substantial losses to us from, among other things, injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties and suspension of operations.

In addition, we may be liable for environmental damages caused by previous owners of property we purchase and lease. As a result, we may incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate the funds available for exploration, development or acquisitions or result in the loss of our properties.

In accordance with customary industry practices, we maintain insurance against some, but not all, potential losses. We do not carry business interruption insurance or protect against loss of revenues. Any insurance we obtain may not be adequate to cover any losses or liabilities. We cannot predict the continued availability of insurance or the availability of insurance at premium levels that justify its purchase. We may elect to self-insure if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations.

We participate in a small number of our wells on a non-operated basis, and accordingly are limited in our ability to control the risks associated with oil and natural gas operations with respect to those wells.

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Title to Properties

Oil and Natural Gas 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 thorough title examination and perform curative work with respect to significant defects. 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 on such property. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas 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 KPC Pipeline are constructed within rights-of-way granted by property owners named in the appropriate land records. All of our compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

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

Certain of our rights to lay and maintain pipelines are derived from recorded oil and 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.

Seasonal Nature of Business

Exploration and Production

Seasonal weather conditions and lease stipulations can limit our development activities and other operations and, as a result, we seek to perform a significant percentage of our development during the spring and summer months. These seasonal anomalies can pose challenges for meeting our well development

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objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

In addition, freezing weather, winter storms and flooding in the spring and summer have in the past resulted in a number of our wells being off-line for a short period of time, which 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.

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months thereby affecting the price we receive for natural gas. Seasonal anomalies such as mild winters and hot summers sometimes lessen this fluctuation.

Interstate Pipelines

Due to the nature of the markets served by the KPC Pipeline, primarily the metropolitan 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. This provides for higher operating costs in the winter months. On a revenue basis, KPC s firm capacity transportation agreements provide for greater use in the winter months. KPC currently generates a disproportionate share of its revenue in the winter months.

Environmental, Health and Safety Matters and Regulation

General

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment, the generation, storage, transportation, handling and disposal of wastes, the safety of employees and governing the protection of human health and safety. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- limit or curtail some or all of the operations of facilities deemed in non-compliance with permits or other legal requirements;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, production, gathering, treating and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, areas inhabited by endangered or threatened species, and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits, plug abandoned wells, and restore, remediate or mitigate impacted environmental media.

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. The oil and gas industry, in particular, recently has come under greater scrutiny by environmental regulators and non-governmental organizations. Any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for or restrictions or other regulatory burdens on operations of the oil and gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

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Waste Management

The Resource Conservation and Recovery Act, or 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 federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. 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. However, 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. Also, 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.

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), which is also known as the Superfund law, imposes strict, and under certain circumstances joint and several, liability for investigation and remediation costs on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may also be subject to liability for damages to natural resources, and for the costs of certain environmental studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease or operate numerous properties that have been used for oil and gas exploration, production, and transportation for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. In fact, there is evidence that petroleum spills or releases have occurred in the past at some of the properties owned or leased by us. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, including wastes disposed of or released by us or prior owners or operators in accordance with then current laws or otherwise, remediate contaminated property, perform plugging or pit closure operations to prevent future contamination, or take other environmental response actions.

Water Discharges and Water Quality

The Clean Water Act (CWA) and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants in waste water and storm water, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The CWA regulates storm water run-off from oil and gas production operations and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of the CWA may require appropriate containment berms and similar structures to help prevent the contamination of navigable

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waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. Federal and state regulatory agencies can also impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Our operations also produce wastewaters that are disposed via underground injection wells. These activities are regulated by the Safe Drinking Water Act (SDWA) and analogous state and local laws. The underground injection well program under the SDWA classifies produced wastewaters and imposes controls relating to the drilling and operation of the wells as well as the quality of the injected wastewaters. This program is designed to protect drinking water sources and requires a permit from the EPA or the designated state agency. Currently, our operations comply with all applicable requirements and have a sufficient number of operating injection wells. However, a change in the regulations or the inability to obtain new injection well permits in the future may affect our ability to dispose of the produced waters and ultimately affect the results of operations.

Vast quantities of natural gas deposits exist in deep shale formations. It is customary in our industry to recover natural gas from these deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating artificial cracks, or fractures, in shale formations deep underground by pumping water, sand and other additives under high pressure into a shale gas formation. These deep shale gas formations are often geologically separated and isolated from any fresh ground water supplies by thousands of feet of protective rock layers. Our well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into overlying aquifers. Legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing. Current proposals include the elimination of the exclusion of hydraulic fracturing from the definition of underground injection under the SDWA, which would subject hydraulic fracturing to SDWA permitting requirements. Such efforts could have an adverse effect on our operations.

The primary federal law for oil spill liability is the Oil Pollution Act, or OPA, which addresses three principal areas of oil pollution: prevention, containment, and cleanup. OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be subject to oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills.

Air Emissions

The Federal Clean Air Act (CAA) and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. Such laws and regulations may require a facility to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain or strictly comply with air permits containing various emissions and operational limitations or utilize specific emission control technologies to limit emissions. In addition, EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. Moreover, depending on the state-specific statutory authority, states may be able to impose air emissions limitations that are more stringent than the federal standards imposed by EPA. Federal and state regulatory agencies can also impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations.

Permits and related compliance obligations under the CAA or state counterpart laws, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas, may require oil and gas exploration, production and transportation operations to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. Oil and gas exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or use specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. Historically, air pollution control has become more stringent over time. This trend is expected to continue. The cost of technology and systems to control air pollution to meet regulatory requirements is significant today. These costs are expected to increase as air pollution control requirements increase. However, any new requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Climate Change

Legislative and regulatory measures to address concerns that emissions of certain gases, commonly referred to as greenhouse gases (including carbon dioxide and methane) (GHGs), may be contributing to warming of the Earth s atmosphere are in various phases of discussions or implementation at the international, national, regional, and state levels. The oil and gas industry is a direct source of certain GHG emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. In the United States, federal legislation requiring GHG controls is under consideration. In addition, EPA is taking steps that would result in the regulation of GHGs as pollutants under the Clean Air Act (CAA).

In September 2009, EPA issued a Mandatory Reporting of Greenhouse Gases final rule, which took effect on December 29, 2009. This rule establishes a comprehensive scheme of regulations that require monitoring and reporting of GHG emissions on an annual basis by operators of stationary sources in the U.S. emitting more than established annual thresholds of carbon dioxide-equivalent GHG emissions. Monitoring and recordkeeping of GHG emissions requirements began January 1, 2010 and reporting requirements obligations begin March 31, 2011 for emissions occurring in 2010. Although the GHG reporting rule does not control GHG emission levels from any facilities, it will still cause us to incur monitoring and reporting costs for GHG emissions that are subject to the rule. Some of our facilities include source categories that are subject to the GHG reporting requirements included in the final rule. Furthermore, in December 2009, EPA indicated that it had drafted and plans to propose additional GHG reporting rules specifically for the oil and gas industry. The proposal is currently undergoing interagency review. The proposed rules will likely apply to natural gas transmission, compression and distribution, *i.e.*, fugitive and vented methane emissions, and potentially to emissions from other activities we conduct. If EPA adopts regulations that require reporting of fugitive and vented methane emissions from the oil and gas industry, this will increase our monitoring and reporting costs.

In December 2009, EPA published a final rule, the Endangerment Finding , finding that GHGs in the atmosphere endanger public health and welfare, and that emissions of GHGs from mobile sources cause or contribute to GHG pollution. The Endangerment Finding took effect on January 14, 2010. While the Endangerment Finding does not impose any direct requirements on industry or other entities, the rule allows EPA to promulgate motor vehicle GHG emission standards. EPA is expected to promulgate such standards in March 2010 and they would take effect sometime thereafter. Motor vehicle emission standards could impact our operations by effectively reducing demand for motor fuels from crude oil. Furthermore, EPA has asserted that final motor vehicle GHG emission standards will trigger construction and operating permit requirements for stationary sources. In September 2009, EPA proposed a rule that would tailor permit applicability thresholds for GHG emissions such that only large stationary sources will be required to obtain air permits for new or modified facilities. Promulgation of the motor vehicle standards and resulting triggering of permitting requirements for GHG emissions from stationary sources could potentially affect our operations and ability to obtain

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air permits for new or modified facilities. EPA s Endangerment Finding has however been challenged and will likely be subject to litigation, and legislation has been proposed to overturn or delay its implementation.

Legislation and regulations related to control or reporting of GHG emissions are also in various stages of discussions or implementation in many of the states in which we operate. Lawsuits have been filed seeking to force the federal government to regulate GHG emissions under the CAA and to require individual companies to reduce GHG emissions from their operations. These and other lawsuits may result in decisions by state and federal courts and agencies that could impact our operations and ability to obtain certifications and permits to construct future projects.

Passage of climate change legislation or other federal or state legislative or regulatory initiatives that regulate or restrict GHG emissions in areas in which we conduct business could adversely affect the demand for oil and gas, and depending on the particular program adopted 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 emissions, pay any taxes related to our GHG emissions and/or administer and manage a GHG emissions program. It could also affect entities that provide goods and services to us and indirectly have an adverse affect on our business as a result of increases in costs or availability of goods and services.

In addition to potential impacts on our business directly or indirectly resulting from climate change legislation or regulations, our business also could be negatively affected by climate change related physical changes or changes in weather patterns. An increase in severe weather patterns could result in damages to or loss of our physical assets, impact our ability to conduct operations and/or result in a disruption of our customer s operations. These and other climate change related physical changes could also affect entities that provide goods and services to us and indirectly have an adverse affect on our business as a result of increases in costs or availability of goods and services. Although we do not believe that we would be impacted to a greater degree than other similarly situated producers of oil and natural gas, a stringent GHG control program could have an adverse effect on our cost of doing business and could reduce demand for the oil and natural gas we produce. Please read Part I, Item 1A. Risk Factors Risks Related to Our Business Recent and future environmental laws and regulations may significantly limit, and increase the cost of, our exploration, production and transportation operations.

Hydrogen Sulfide

Hydrogen sulfide gas is a byproduct of sour gas treatment. Exposure to unacceptable levels of hydrogen sulfide (known as sour gas) is harmful to humans, and prolonged exposure can result in death. We employ numerous safety precautions to ensure the safety of our employees. There are various federal and state environmental and safety requirements that apply to facilities using or producing hydrogen sulfide gas. Notwithstanding compliance with such requirements, common law causes of action are available to persons damaged by exposure to hydrogen sulfide gas.

National Environmental Policy Act

Oil and gas exploration and production activities on federal lands or that require certain federal permits are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. If we were to conduct any exploration and production activities on federal lands in the future or initiate other projects subject to NEPA requirement, those activities would need to undergo the NEPA review process including potential evaluation of any GHG impacts from proposed activities. This process has the potential to delay and potentially prevent the development of an oil and gas project.

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Endangered Species Act

The Endangered Species Act (ESA) and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Although we believe that our current operations do not affect endangered or threatened species or their habitats, the existence of endangered or threatened species in areas of future operations and development could cause us to incur additional mitigation costs or become subject to construction or operating restrictions or bans in the affected areas.

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The Occupational Safety and Health Administration s hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other comparable laws.

We believe that we are in substantial compliance with all existing environmental and safety laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2009. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2010. However, accidental spills or releases may occur in the course of our operations, and we cannot assure you that we will not incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. Moreover, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our business, financial condition, or results of operations.

Other Regulation of the Oil and Gas Industry

The oil and gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including gas and oil facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Exploration and Production

Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;

the surface use and restoration of properties upon which wells are drilled;

the plugging and abandoning of wells; and

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 other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may 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 the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, some states impose a production or severance tax with respect to the production and sale of oil, gas and gas liquids within its jurisdiction.

The Cherokee Basin has been an active oil and natural gas 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 into with the landowner. 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. The Kansas Corporation Commission s current interpretation of Kansas law is consistent with our position.

Interstate Pipelines

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation of natural gas and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. 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 also 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 operations, and we note that some of FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other interstate pipelines with which we compete.

The Energy Policy Act of 2005, or EP Act 2005, gave FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended the Natural Gas Act of 1938, or NGA, to prohibit market manipulation and also amended the NGA and the Natural Gas Policy Act of 1978, or NGPA, to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of FERC to up to $1,000,000 per day, per violation. In addition, FERC issued a final rule effective January 26, 2006 regarding market manipulation, which makes 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. This final rule works together with FERC s enhanced penalty authority to provide increased oversight of the natural gas marketplace.

Although natural gas prices are currently unregulated, FERC promulgated regulations in December 2007 requiring natural gas sellers to submit an annual report, beginning in July 2009, reporting certain information regarding natural gas purchases and sales (*e.g.*, total volumes bought and sold, volumes bought and sold and

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index prices). Additionally, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation or regulations to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress, the FERC, or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of condensate and gas liquids are not currently regulated and are made at market prices.

State Severance, Production and Other Taxes

Kansas currently imposes a severance tax on the gross value of oil and natural gas produced from wells having an average daily production during a calendar month with a gross value of more than $87 per day. Kansas also imposes oil and natural gas conservation assessments per barrel of oil and per 1,000 cubic feet of gas produced. In general, oil and natural gas leases and oil and natural gas wells (producing or capable of producing), including all equipment associated with such leases and wells, are subject to an ad valorem property tax.

Oklahoma imposes a monthly gross production tax and excise tax based on the gross value of the oil and natural gas produced. Oklahoma also imposes an excise tax based on the gross value of oil and natural gas produced. All property used in the production of oil and natural gas is exempt from ad valorem taxation if gross production taxes are paid. Lastly, the rate of taxation of locally assessed property varies from county to county and is based on the fair cash value of personal property and the fair cash value of real property.

West Virginia imposes a severance tax equal to five percent of the gross value of oil and natural gas produced and a similar severance tax on CBM produced. West Virginia also imposes an additional annual privilege tax equal to 4.7 cents per Mcf of natural gas produced.

New York imposes an annual oil and natural gas charge based on the amount of oil or natural gas produced each year.

States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may limit the amounts of oil and natural gas that may be produced from our wells and may limit the number of wells or locations drilled.

Federal Regulation of Transportation of Gas

FERC regulates interstate natural gas pipelines pursuant to the NGA, NGPA and EP Act 2005. Generally, FERC s authority over interstate natural gas pipelines extends to:

- 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.

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

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

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. We believe our natural gas gathering pipeline facilities meet the traditional tests used by FERC to distinguish gathering facilities from transmission facilities. However, if FERC were to determine that the facilities perform primarily a transmission function, rather than a gathering function, these facilities may become subject to regulation as interstate natural gas pipeline facilities and we may be subject to fines. 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 would substantially increase our operating costs and would adversely affect our profitability.

Additionally, while gathering facilities and other non-interstate pipelines are generally exempt from FERC s jurisdiction, FERC adopted internet posting requirements in November 2008 that are applicable to certain gathering facilities and other non-interstate pipelines meeting size and other thresholds. Various parties requested rehearing of the FERC rule adopting the new posting requirements and the FERC granted an extension of time to comply with the new requirements until 150 days following the issuance of an order addressing the requests for rehearing. On January 21, 2010, FERC issued a rehearing order that generally upheld the new reporting requirements while making certain revisions and clarifications. Importantly, FERC upheld provisions specifying, among other things, that the new reporting requirements are only applicable to 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 new posting requirements. Nevertheless, it is possible that we could become subject to the new 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 new posting requirements, we would likely incur additional compliance expenses.

State Regulation of Natural Gas Gathering Pipelines

Our natural gas 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 compliant-based rate regulation. We are licensed as an operator of a natural gas gathering system with the Kansas Corporation Commission, or 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, New York or West Virginia.

On those portions of our gas 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. 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

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our rates with respect to the wells that were the subject of the complaint. We are not aware of any instance in which either the KCC or the OCC has made such a determination in the past.

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

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state 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 also 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, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines.

Pipeline Safety

Our pipelines are subject to regulation by the U.S. Department of Transportation, or the DOT, under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The NGPSA covers the pipeline transportation of natural gas and other gases and requires any entity that owns or operates pipeline facilities to comply with the regulations under the NGPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. 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.

Other

In addition to existing laws and regulations, the possibility exists that new legislation or regulations may be adopted which would 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, FERC, the Minerals Management Service, 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. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely.

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. Moreover, changes in any of these laws and regulations could have a material adverse effect on our business. 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.

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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 to ensure that our operations are conducted in substantial regulatory compliance.

Employees

As of December 31, 2009, we had a staff of 156 field employees in offices located in Kansas, Oklahoma, Pennsylvania, and West Virginia. We have 69 pipeline operations employees. We have 73 executive and administrative personnel located at our headquarters in Oklahoma City and our office in Houston, Texas. None of our employees are covered by a collective bargaining agreement. Management considers its relations with our 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 Committee Charter; and
- Code of Business Conduct and Ethics.

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GLOSSARY OF SELECTED TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this Annual Report on Form 10-K. Some of the definitions below have been abbreviated from the applicable definition contained in Rule 4-10(a) of Regulation S-X.

Appalachian Basin. One of the United States oldest oil and natural gas producing regions that extends from Alabama to Maine.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bbls/d. Stock tank barrels per day.

Bcf. One billion cubic feet of gas.

Bcfe. One billion cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of crude oil, condensate or gas liquids.

Brown Shales. Fine grained rocks composed largely of clay minerals that contain little organic matter. Some of these shales immediately overlay the Marcellus Shale.

British Thermal Unit. The quantity of heat required to raise the temperature of a one pound mass of water by one degree Fahrenheit.

CBM. Coal bed methane.

Cherokee Basin. A fifteen-county region in southeastern Kansas and northeastern Oklahoma.

Completion. The installation of permanent equipment for the production of oil or gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Developed Acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed Reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development Costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.

Development Project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Devonian Sands. Sands generally younger and shallower than the Marcellus Shale that occur in portions of Ohio, New York, Pennsylvania, West Virginia, Kentucky and Tennessee and generally located at depths of less than 5,000 feet.

Dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Dth. One dekatherm, equivalent to one million British Thermal Units.

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Earned acreage. The number of acres that has been assigned as a result of fulfilling conditions or requirements of an agreement.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Exploitation. A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

Farm-out. An agreement under which the owner of a working interest in an oil or gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in while the interest transferred by the assignor is a farm-out. Acreage is considered to be unearned, until the conditions of the agreement are met, and an assignment of interest has been made.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Frac/fracturing. The method used to increase the deliverability of a well by pumping a liquid or other substance into a well under pressure to crack and prop open the hydrocarbon formation.

Gas. Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

Gathering system. Pipelines and other equipment used to move gas from the wellhead to the trunk or the main transmission lines of a pipeline system.

Gross acres or gross wells. The total acres or wells, as the case may be, in which we have a working interest.

Horizon or formation. The section of rock, from which gas is expected to be produced.

Marcellus Shale. A black, organic-rich shale formation in the Appalachian Basin that occurs in much of Ohio, West Virginia, Pennsylvania and New York and portions of Maryland, Kentucky, Tennessee and Virginia. The fairway of the Marcellus Shale is generally located at depths between 3,500 and 8,000 feet and ranges in thickness from 50 to 150 feet.

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of gas.

Mcf/d. One Mcf per day.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of crude oil, condensate or gas liquids.

MMbbl. One million barrels of oil.

Mmbtu. One million British Thermal Units.

Mmcf. One million cubic feet of gas.

Mmcf/d. One Mmcf per day.

Mmcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of crude oil, condensate or gas liquids.

Mmcfe/d. One million cubic feet equivalent per day.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

Net production. Production that is owned by us less royalties and production due others.

Net revenue interest. The percentage of revenues due an interest holder in a property, net of royalties or other burdens on the property.

NGLs. Natural gas liquids being the combination of ethane, propane, butane and natural gasoline that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil, condensate and NGLs.

Permeability. The ability, or measurement of a rock s ability, to transmit fluids, typically measured in darcies or millidarcies.

Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced.

Productive well. A well that is currently producing hydrocarbons or any exploratory, development or extension well that is reasonably believed to be capable of producing hydrocarbons.

Proved developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casings in existing wells.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved reserves. Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience 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 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.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage directly offsetting development spacing areas that are reasonably certain of production when drilled, or from existing wells where a relatively major expenditure is required for recompletion.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

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Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resources. Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations.

Royalty Interest. A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil or natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and gas. A royalty interest owner has no right to consent to or approve the operation and development of the property, while the owners of the working interests have the exclusive right to exploit the mineral on the land.

Service well. A well drilled or completed for the purpose of supporting production in an existing field.

Shut in. To close down a well temporarily.

Standardized measure. The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions.

Unconventional resource development. A development in which the targeted reservoirs generally fall into three categories: (1) tight sands, (2) coal beds, and (3) gas shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require stimulation treatments or other special recovery processes in order to produce economic flow rate.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas regardless of whether or not such acreage contains proved reserves.

Undeveloped reserves. Undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Unearned acreage. The number of acres that has not yet been assigned, but may be developed per the terms of an agreement.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

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ITEM 1A. *RISK FACTORS*

Risks Related to Our Business

Our independent registered public accounting firm has expressed substantial doubt about our predecessor s ability to continue as a going concern.

The independent auditor s report accompanying our predecessor s audited consolidated financial statements for the year ended December 31, 2009 included in this Annual Report on Form 10-K contains a statement expressing substantial doubt as to our predecessor s ability to continue as a going concern. The factors contributing to this concern include our significant losses from 2003 through 2009, the amount of our debt obligations due during 2010 and our ability to comply with the financial covenants related to our debt facilities. If we are unable to refinance our debt, raise additional equity capital and/or complete some other strategic transaction, then we may be forced to make a bankruptcy filing or take other actions that could have a material adverse effect on our business, the price of our common stock and our results of operations, financial position and cash flows.

We have identified significant and pervasive material weaknesses in our internal control over financial reporting, which may persist.

In connection with management s review of our internal controls as of December 31, 2009, the following control deficiencies that constituted material weaknesses related to the following items were identified:

- We did not maintain a sufficient control environment. The control environment, which is the responsibility of senior management, sets the tone of the organization, influences the control consciousness of its people, and is the foundation for all other components of internal control over financial reporting. Specifically, during the first two quarters of the year, management s attention was focused on the restatement and reaudit of prior year financial statements and the recombination, which resulted in the full implementation of our remediation plan being delayed until the third quarter of 2009. During the first two quarters of 2009, only specific identified risks related to items such as the fraud hotline, segregation of duties and cash management controls were actively monitored.

- We did not maintain sufficient monitoring controls to determine the adequacy of our internal control over financial reporting.

- We did not maintain sufficient controls over certain of our period-end financial close and reporting processes.

- We did not maintain sufficient controls to ensure completeness and accuracy of stock compensation costs.

- We did not maintain sufficient controls to ensure completeness and accuracy of depreciation, depletion and amortization expense.

- We did not maintain sufficient controls to ensure the accuracy and application of GAAP related to the impairment of oil and gas properties and, specifically, to determine, review and record oil and gas property impairments.

Based on the material weaknesses described above, management has concluded that our internal control over financial reporting was not effective as of December 31, 2009.

These and other material weaknesses were also identified in connection with management s review of the internal controls of QRCP and QELP as of December 31, 2008, which weaknesses resulted in the misstatement of certain of QRCP s and QELP s annual and interim consolidated financial statements during 2006, 2007 and 2008.

Additional measures may be necessary and these measures, along with other measures we expect to take to improve our internal control over financial reporting, may not be sufficient to address the deficiencies identified or ensure that our internal control over financial reporting is effective. If we are unable to provide reliable and timely financial external reports, our business and prospects could suffer material adverse effects.

In addition, we may in the future identify further material weaknesses or significant deficiencies in our internal control over financial reporting.

The recent financial crisis and current economic conditions have had, and may continue to have, a material adverse impact on our business and financial condition.

From the second half of 2008 through late 2009, global financial markets experienced a period of unprecedented turmoil and upheaval characterized by extreme volatility and declines in prices of securities, diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of financial institutions and an unprecedented level of intervention from the U.S. federal government and other governments. In particular, the cost of raising money in the debt and equity capital markets increased substantially while the availability of funds from those markets generally diminished significantly. Also, as a result of concerns about the stability of financial markets and the solvency of counterparties, the cost of obtaining money from the credit markets increased as many lenders and institutional investors increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on more onerous terms and, in some cases, ceased to provide any new funding.

A continuation of current economic conditions could result in further reduced demand for oil and natural gas and put renewed downward pressure on the prices for oil and natural gas, which fell dramatically since reaching historic highs in July 2008. These price declines negatively impacted our revenues and cash flows. Difficult economic conditions could materially adversely affect our business and financial condition. For example:

- our ability to obtain credit and access the capital markets to fund the exploration or development of reserves, the construction of additional assets or the acquisition of assets or businesses from third parties may continue to be restricted;

- the counterparties to our derivative financial instrument contracts could default on their contractual obligations;

- the values we are able to realize in asset sales or other transactions we engage in to raise capital may be reduced, thus making these transactions more difficult to consummate and less economic; and

- the demand for oil and natural gas could decline due to deteriorating economic conditions, which could adversely affect our business, financial condition or results of operations.

No later than the first half of 2010, we will need to either refinance our debt to allow for available capital or raise a significant amount of equity capital to fund our planned drilling program and pay down outstanding indebtedness, including principal, interest and fees of approximately $21 million due under QRCP s credit agreement on July 11, 2010. In addition, QELP is required to make principal payments on its credit facility of at least $4 million, $3 million and $4 million in the first, third and fourth quarters of 2010, respectively. We may not be able to refinance our debt or raise a sufficient amount of debt or equity capital for these purposes at the appropriate time due to market conditions or our financial condition and prospects, or we may have to incur indebtedness on unattractive terms or issue shares at a significant discount to the market price or incur debt on terms that are not favorable to us.

Due to these factors, funding may not be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or if funding is available only on unfavorable terms, we may be unable to meet our obligations as they come due or be required to post collateral to support our obligations, or we may be unable to implement our development plans, enhance our business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues, results of operations, or financial condition or cause us to file for bankruptcy. In addition, if we issue and sell additional shares in an equity offering, existing stockholders may be diluted and our stock price may decrease due to the additional shares available in the market.

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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 natural 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 current global credit and economic environment has resulted in reduced demand for natural gas and significantly lower natural gas prices. Gas prices have seen a greater percentage decline over the past twelve months than oil prices due in part to an ample supply of natural gas on the market and in storage. The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities, and therefore their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and will likely continue to be volatile in the future. For example, during 2009, the near month NYMEX natural gas futures price ranged from a high of $6.07 per Mmbtu to a low of $2.51 per Mmbtu. Approximately 98% of our production is natural gas. The prices that we receive for our production, and the levels of our production, depend on a variety of factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil and natural gas;
- the price and level of foreign imports of oil and natural gas;
- the level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural 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 natural gas prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the costs, proximity and capacity of natural 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 natural gas, and a drop in prices will significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

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

negatively impact the value of our reserves because declines in oil and natural gas prices would reduce the amount of oil and natural 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 natural gas available for transport on the KPC Pipeline; and

limit our ability to borrow money or raise additional capital.

Future price declines may result in a write-down of our asset carrying values.

Lower oil and natural gas prices may not only decrease our revenues, profitability and cash flows, but also reduce the amount of oil and natural 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 natural gas prices have had and may continue to render a significant number of our planned exploration and development projects uneconomic. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil or gas properties, pipelines or other long-lived assets for impairments. We will be required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and may, therefore, require a write-down of such carrying value.

For example, due to depressed natural gas prices in 2009, revisions resulting from further technical analysis and production during the year, our proved reserves decreased 57.2% to 74.8 Bcfe at December 31, 2009 from 174.8 Bcfe at December 31, 2008, and the standardized measure of our proved reserves decreased 69.2% to $50.6 million as of December 31, 2009 from $164.1 million as of December 31, 2008. The December 31, 2009 reserves were calculated using a twelve-month average price of $3.87 per Mmbtu (adjusted for basis differential, prices were $4.13 per Mmbtu in the Appalachian Basin and $3.27 per Mmbtu in the Cherokee Basin) compared to $5.71 per Mmbtu at December 31, 2008. We recognized a non-cash impairment of $102.9 million during the first quarter of 2009. At the end of the third quarter of 2009, the ceiling test computation resulted in the carrying costs of our unamortized proved oil and natural gas properties, net of deferred taxes, exceeding the September 30, 2009 present value of future net revenues by approximately $11.1 million. As a result of subsequent increases in spot prices, the need to recognize an impairment for the quarter ended September 30, 2009 was eliminated. No impairment was required for the quarter ended December 31, 2009. We may incur further impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred and result in a reduction in our credit facility borrowing base.

We recorded an impairment charge on our interstate and gathering pipelines and related contract-based intangible assets in 2009.

In connection with the preparation and audit of our consolidated financial statements for the year ended December 31, 2009, we recorded a non-cash impairment charge of $165.7 million on our interstate and gathering pipelines and related contract-based intangible assets in the fourth quarter of 2009. This non-cash impairment charge is due to the loss of MGE, a significant customer of the KPC Pipeline, during the fourth quarter of 2009, as well as the amendments to our credit agreements in December 2009. The amendments to our credit agreements resulted in a reduction of expected drilling activity in the Cherokee Basin. Please read As a result of our financial condition, we have had to significantly reduce our capital expenditures, which will ultimately reduce cash flow and result in the loss of some leases and The revenues of our interstate pipeline business are generated under contracts that must be renegotiated periodically.

As a result of our financial condition, we have had to significantly reduce our capital expenditures, which will ultimately reduce cash flow and result in the loss of some leases.

Due to the global economic and financial crisis, the decline in commodity prices, the unauthorized transfers of funds by former senior management and restrictions in our credit agreements, as described in more detail in other risk factors, we have not been able to raise the capital necessary to implement our drilling plans for 2009 and 2010. We reduced our total capital expenditures from $267.1 million in 2008 to $9.6 million in 2009. In addition, we drilled seven new wells in 2009, after completing 328 new wells in 2008. The effect of this reduced capital expenditure and drilling program is that we may not be able to maintain our reserves levels and may lose leases or other development rights that require a certain level of drilling activity. Please read Certain of our undeveloped acreage is subject to leases or other agreements that may expire in the near future and We recorded an impairment charge on our interstate and gathering pipelines and related contract-based intangible assets in 2009.   During 2010, we plan to drill nine gross wells and complete 108 gross wells that were previously drilled but not completed at a total estimated cost of $26 million, but we may not be able to obtain the capital to achieve this plan.

We are highly leveraged.

As of December 31, 2009, we had approximately $372.5 million of contractual commitments outstanding, consisting of debt service requirements and operating lease commitments. We anticipate that we may in the future incur additional debt for financing our growth. 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 natural gas prices, decreased production or other factors could make it difficult for us to pay our liabilities. Any failure by us to meet these obligations could result in litigation, non-performance by contract counterparties or bankruptcy;

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

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

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

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

There may be events of default under QRCP s, QELP s and QMLP s indebtedness enabling the lenders to accelerate such indebtedness, which could lead to the foreclosure of collateral and the bankruptcy of us, QRCP, QELP and QMLP.

QRCP and QELP have been in default under their respective credit agreements. In May 2009, QRCP entered into an amendment to its credit agreement to, among other things, waive certain events of default related to its financial covenants and collateral requirements and to extend certain financial reporting deadlines.

In June 2009, QRCP, QELP and Quest Cherokee, LLC (Quest Cherokee) entered into amendments to their respective credit agreements that, among other things, deferred until August 15, 2009 the obligation to deliver to the Royal Bank of Canada (RBC), as administrative agent under the credit agreements, certain financial information. The QRCP amendment also waived financial covenant (namely the interest coverage ratio and leverage ratio) events of default for the fiscal quarter ended June 30, 2009, waived any mandatory prepayment due to any collateral deficiency during the fiscal quarter ended September 30, 2009, and deferred until September 30, 2009 the interest payment due on June 30, 2009, which amount was represented by a promissory note bearing interest at the Base Rate (as defined in QRCP s credit agreement) with a maturity

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date of September 30, 2009. On September 11, 2009, QRCP further amended its credit agreement to extend the maturity date of the interest deferral note to July 11, 2010 while allowing interest for the third quarter of 2009, fourth quarter of 2009, first quarter of 2010 and second quarter of 2010 to be deferred to July 11, 2010 as well. The quarterly principal payments of $1.5 million due September 30, 2009, December 31, 2009, March 31, 2010 and June 30, 2010 were also effectively deferred until July 11, 2010 at which time all $6 million will be due in order to satisfy certain facility fee reduction conditions. Please read Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Agreements QRCP Interest Rate and Other Fees. Thereafter, QRCP will be required to make a principal repayment of $1.5 million at the end of each calendar quarter until maturity. If QRCP is not able to pay in full all the amounts due on July 11, 2010 (approximately $21 million), the entire amount of QRCP s credit facility would become due and payable. QRCP may not be able to pay such amount on that date and may not be able to obtain further extensions of the maturity date.

An event of default under either of QELP s credit agreements would cause an event of default under QELP s other credit agreement.

If there is an event of default under any of the credit agreements, the lenders thereunder could accelerate the indebtedness and foreclose on the collateral securing that credit agreement. As of December 31, 2009, there was $35.7 million outstanding under the QRCP credit agreement, $145.0 million outstanding under the QELP credit agreement, $29.8 million outstanding under the QELP second lien loan agreement and $118.7 million under the QMLP credit agreement.

In July 2009, QELP s borrowing base under its credit agreement was reduced from $190 million to $160 million. Effective December 17, 2009, QELP s borrowing base under its credit agreement was further reduced to $145 million in connection with another borrowing base redetermination, which resulted in a borrowing base deficiency of $15 million. QELP repaid the borrowing base deficiency on December 17, 2009 in connection with the execution of the amendment to the Quest Cherokee credit agreement. QELP s borrowing base may be further reduced in connection with future borrowing base redeterminations, which will occur on a quarterly basis beginning May 1, 2010. QELP may not be able to repay any borrowing base deficiency resulting from any future reduction in the borrowing base.

In addition, as a result of the recent expiration of MGE s firm transportation contract with the KPC Pipeline and the expected decrease in 2010 in the gathering and compression fees charged under the midstream services agreement between QELP and a subsidiary of QMLP as a result of the low natural gas prices in 2009, QMLP may not be in compliance with the total leverage ratio covenant in its credit agreement commencing with the second quarter of 2010, if it is not able to reduce its expected total indebtedness as of June 30, 2010 and/or increase its anticipated EBITDA for the quarter ended June 30, 2010. If QMLP were to default, the lenders could accelerate the entire amount due under the QMLP credit agreement.

If QELP, QRCP or QMLP is required to pay the full amounts of its indebtedness upon acceleration, it may be able to raise the funds only by selling assets or it may be unable to raise the funds at all, in which event we may be forced to file for bankruptcy protection or liquidation.

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 and the terms of any future financing agreements restrict our ability to finance future operations or capital needs or to engage, expand or pursue our business activities. Our credit agreements and any future financings agreements may restrict our ability to:

- incur indebtedness;

make capital expenditures above specified amounts;

grant liens;

pay dividends;

- redeem or repurchase equity interests;
- make certain acquisitions and investments, loans or advances;
- lease equipment;
- enter into a merger, consolidation or sale of assets;
- dispose of property;
- enter into hedging arrangements with certain counterparties;
- limit the use of loan proceeds; and
- enter into transactions with affiliates, including transactions and transfers of funds among QRCP, QELP and QMLP.

We also are required to comply with certain financial covenants and ratios. 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.

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.

Former senior management were terminated in 2008 following the discovery of various misappropriations of funds of QRCP and QELP.

In August of 2008, Jerry Cash, the former chairman, president and chief executive officer of QRCP, the general partner of QELP (QEGP) and the general partner of QMLP (QMGP), resigned and David E. Grose, the former chief financial officer of QRCP, QEGP and QMGP, was terminated, following the discovery of the misappropriation of $10 million principally from QRCP by Mr. Cash with the assistance of Mr. Grose from 2005 through mid-2008. Additionally, the Oklahoma Department of Securities has filed a lawsuit alleging that Mr. Grose and Brent Mueller, the former purchasing manager of QRCP, each received kickbacks of approximately $0.9 million from several related suppliers over a two-year period and that during the third quarter of 2008, they also engaged in the direct theft of $1 million for their personal benefit and use. In March 2009, Mr. Mueller pled guilty to one felony count of misprision of justice. We have filed lawsuits against all three of these individuals seeking an asset freeze and damages related to the transfers, kickbacks and thefts. Pursuant to a settlement agreement with Mr. Cash, we recovered assets valued at $3.4 million from him and released all further claims against him. As a result of these activities, we recorded an aggregate consolidated loss of $6.6 million. We have incurred costs totaling approximately $8.5 million in connection with the investigation of these misappropriations, legal fees, accountants fees and other related expenses. We may not be successful in recovering any additional amounts. Any additional recoveries may consist of assets other than cash and accurately valuing such assets in the current economic climate may be difficult. Any amounts recovered will be recognized by us for financial accounting purposes only in the period in which the recovery occurs.

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QRCP and QELP are involved in securities lawsuits that may result in judgments, settlements, and/or indemnity obligations that are not covered by insurance and that may have a material adverse effect on us.

Between September 2008 and November 2009, four federal securities class action lawsuits, two federal individual securities lawsuits, two federal derivative lawsuits and three state court derivative lawsuits have been filed naming QRCP, QELP and certain current and former officers and directors as defendants. The securities lawsuits allege the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material facts concerning the unauthorized transfers of funds by former management described above and seek class certification, money damages, interest, attorneys fees, costs and expenses. The complaints allege that, as a result of these actions, QRCP s stock price and QELP s unit price were artificially inflated. The derivative lawsuits assert claims for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets and unjust enrichment and seek disgorgement, money damages, costs, expenses and equitable or injunctive relief. Additional lawsuits may be filed. For more information, please read Part I, Item 3. Legal Proceedings.

We have incurred and will continue to incur substantial costs, legal fees and other expenses in connection with the defense against these claims. In addition, the final settlements or the courts final decisions in the securities cases could result in judgments against QRCP and QELP that are not covered by insurance or which exceed the policy limits. QRCP and QELP may also be obligated to indemnify certain of the individual defendants in the securities cases, which indemnity obligations may not be covered by insurance. QRCP and QELP have received letters from their directors and officers insurance carriers reserving their rights to limit or preclude coverage under various provisions and exclusions in the policies, including for the committing of a deliberate criminal or fraudulent act by a past, present, or future chief executive officer or chief financial officer. QELP has received a letter from its then directors and officers liability insurance carrier stating that the carrier will not provide insurance coverage to QELP based on Mr. Cash s alleged written admission that he engaged in acts for which coverage is excluded. The carrier also reserved its rights to deny coverage under various other provisions and exclusions in the policies. QELP continues to evaluate its options regarding the insurer s stated coverage position.

Following the closing of the recombination, our subsidiaries QRCP and QELP will still be parties to these lawsuits, and we now face the same risks with respect to these lawsuits as QRCP and QELP. We might not have sufficient cash on hand to fund any such payment of expenses, judgments, settlements and indemnity obligations and might be forced to file for bankruptcy or take other actions that could have a material adverse effect on our financial condition and the price of our common stock. Furthermore, certain of our officers and directors may continue to be subject to these actions for some time, which could adversely affect the ability of our management and board of directors to implement our business strategy.

U.S. government investigations could affect our results of operations and financial condition.

Numerous government entities are currently conducting investigations of QRCP, QELP and some of their former officers and directors. The Oklahoma Department of Securities has filed lawsuits against Mr. Cash, Mr. Grose and Mr. Mueller. In addition, the Oklahoma Department of Securities, the Federal Bureau of Investigation, the Department of Justice, the Securities and Exchange Commission, the Internal Revenue Service and other government agencies are currently conducting investigations related to QRCP and QELP and the misappropriations by these individuals.

We cannot anticipate the timing, outcome or possible financial or other impact of these investigations. The governmental agencies involved in these investigations have a broad range of civil and criminal penalties they may seek to impose against corporations and individuals for violations of securities laws, and other federal and state statutes, including, but not limited to, injunctive relief, disgorgement, fines, penalties and modifications to business practices and compliance programs. In recent years, these agencies and authorities have entered into agreements with, and obtained a broad range of penalties against, several public corporations and individuals in similar investigations, under which civil and criminal penalties were imposed, including in some cases multi-million dollar fines and other penalties and sanctions. Any injunctive relief, disgorgement, fines, penalties, sanctions or imposed modifications to business practices resulting from these investigations could adversely affect our results of operations and financial condition and our ability to continue as a going concern.

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

We incur costs and expenses for gathering, dehydration, treating and compression of the natural gas that we produce. The terms of some of our existing natural gas leases and other development rights may not, and the terms of some of the natural 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. In 2009, we recovered approximately 74% of the total gathering fees incurred to transport natural gas for our royalty interest owners. On August 6, 2007, certain mineral interest owners filed a putative class action lawsuit against our wholly owned subsidiary Quest Cherokee, that, among other things, alleges Quest Cherokee improperly charged certain expenses to the mineral and/or overriding royalty interest owners under leases covering the acres leased by Quest Cherokee in Kansas. We will be responsible for any judgments or settlements with respect to this litigation. Please see Part I, Item 3. Legal Proceedings for a discussion of this litigation. To the extent that we are unable to charge and recover the full amount of these costs and expenses from our royalty owners, our net income and cash flows will be reduced.

We depend on one customer for sales of substantially all our Cherokee Basin natural gas. A reduction by this customer in the volumes of gas it purchases from us could result in a substantial decline in our revenues and net income.

During 2009, we sold substantially all of our natural gas produced in the Cherokee Basin at market-based prices to ONEOK under a sale and purchase contract, which has an indefinite term but may be terminated by either party on 30 days notice, other than with respect to pending transactions, or less following an event of default. Sales under this contract accounted for approximately 61% of our consolidated revenue for 2009. If ONEOK were to reduce the volume of gas it purchases under this agreement, our revenue and cash flow could decline and our results of operations and financial condition could be materially adversely affected.

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

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

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

Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural 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. Because of our financial condition, we were not able to replace in 2009 the reserves we produced in 2009. Similarly, we may not be able to replace in 2010 the reserves we expect to produce in 2010.

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There is a significant delay between the time we drill and complete a CBM well and when the well reaches peak production. As a result, there will be a significant lag time between when we make capital expenditures and when we will begin to recognize significant cash flow from those expenditures.

Our general production profile for a CBM well averages an initial 5-10 Mcf/d (net), steadily rising for the first twelve months while water is pumped off and the formation pressure is lowered until the wells reach peak production (an average of 50-55 Mcf/d (net)). In addition, there could be significant delays between the time a well is drilled and completed and when the well is connected to a gas gathering system. This delay between the time when we expend capital expenditures to drill and complete a well and when we will begin to recognize significant cash flow from those expenditures may adversely affect our cash flow from operations. Our average cost to drill and complete a CBM well is between $110,000 to $125,000.

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 natural gas in an exact way. Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of oil and natural gas that cannot be directly measured and assumptions concerning future oil and natural gas prices, production levels and operating and development costs. In estimating our level of oil and natural 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. In late 2008, the SEC adopted new rules regarding the classification of reserves that were effective for our December 31, 2009 reserve report. However, the interpretation of these rules and their applicability in different situations remains unclear in many respects. Changing interpretations of the classification standards or disagreements with our interpretations could cause us to write-down reserves. Please read Future price declines may result in a write-down of our asset carrying values.

In addition to proved reserves, which are those quantities of natural gas and crude oil that can be estimated with reasonable certainty to be economically producible within the time period provided by applicable SEC rules, we disclose in this annual report our "probable" and "possible" reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves include additional reserves that are less certain to be recovered than probable reserves. These estimates of probable and possible reserves are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by us.

Our standardized measure is calculated using unhedged oil and natural 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 current costs in effect on the day of estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

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

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural 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 natural 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 natural gas, can adversely affect the economics of a well. Furthermore, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

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

loss of drilling fluid circulation;

unexpected operational events and drilling conditions;

increased risk of wellbore instability due to horizontal drilling;

unusual or unexpected geological formations;

natural disasters, such as fires and floods;

blowouts, surface craterings and explosions; and

uncontrollable flows of oil, gas or well fluids.

A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil or natural gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances. We may drill wells that are unproductive or, although productive, do not produce oil or natural 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.

We have less information regarding reserves and decline rates in the Marcellus Shale than in the Cherokee Basin. Wells drilled to the Marcellus Shale are deeper, more expensive and more susceptible to mechanical problems in drilling and completing than wells in the Cherokee Basin.

As of December 31, 2009, we had drilled two vertical, completed one vertical and drilled and completed two horizontal gross wells in the Marcellus Shale. We have much less information with respect to the ultimate recoverable reserves and the production decline rate in the Marcellus Shale than we have in the Cherokee Basin. The wells to be drilled in the Marcellus Shale will be drilled deeper than in the Cherokee Basin and some may be horizontal wells, which makes the Marcellus Shale wells more expensive to drill and complete. The wells, especially any horizontal wells, are also more susceptible than those in the Cherokee Basin to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore. The fracturing of the Marcellus Shale is more extensive and complicated than fracturing the geological formations in the Cherokee Basin and requires greater volumes of water than conventional gas wells. The management of water and treatment of produced water from Marcellus Shale wells may be more costly than the management of produced water from other geologic formations.

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

In the past, substantially all of the revenues from the KPC Pipeline were generated under two firm capacity transportation contracts with Kansas Gas Service and one firm capacity transportation contract with Missouri Gas Energy. The contracts with KGS generated 59% and 58% of total revenues from the KPC Pipeline for the years ended December 31, 2009 and 2008, respectively, and the contract with MGE generated 32% and 38% of total revenues from the KPC Pipeline for the years ended December 31, 2009 and 2008, respectively. The MGE firm contract, which was for 46,000 Dth/d, expired on October 31, 2009 and was not renegotiated or renewed. The loss of this contract resulted in a non-cash impairment charge related to the KPC Pipeline recorded in 2009. Please read We recorded an impairment charge on our interstate and gathering pipelines and related contract-based intangible assets in 2009. KGS has several contracts for firm capacity on the KPC Pipeline, including contracts for the following capacities and terms (i) 12,000 Dth/d extending through October 31, 2013, (ii) 57,568 Dth/d extending through October 31, 2017, (iii) 6,857 Dth/d extending through March 31, 2017 and (iv) 6,900 Dth/d extending through September 30, 2017. We executed new letter agreements with KGS covering 27,568 Dth/d and 30,000 Dth/d (total of 57.568 Dth/d), both of which would extend through October 31, 2017. The contract for 30,000 Dth/d has provisions for volume decreases after the third year on a sliding basis each year.

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 pipelines;

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

reduced demand and market conditions in the areas we serve;

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

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

We have and may in the future enter into additional derivative arrangements for a significant portion of our oil and natural gas 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 oil and natural gas 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 natural 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 we enter into derivative transactions related to only a portion of our expected production volumes and, as a result, we have direct commodity price exposure on the portion of our production volumes that is not covered by a derivative financial instrument.

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

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

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

Substantially all of our assets are located in the Cherokee Basin and Appalachian Basin. As a result, our business is disproportionately exposed to adverse developments affecting these regions. These 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 these operating areas 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 natural 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

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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 natural 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 natural 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 natural gas industry. These larger companies may have a greater ability to continue drilling activities during periods of low oil and natural 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 our Cherokee Basin gas gathering system, we may face competition in our efforts to obtain additional natural gas volumes. We will compete principally against other producers in the Cherokee Basin with natural gas gathering services. Our competitors may expand or construct gathering systems in the Cherokee Basin that would create additional competition for the services we provide to our customers.

With respect to the KPC Pipeline, we compete with other interstate and intrastate pipelines in the transportation of natural gas for transportation customers primarily on the basis of transportation rates, access to competitively priced supplies of natural gas, markets served by the 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 PipeLine Company in the Kansas City market and Southern Star Central Gas Pipeline, Inc., Atmos Energy Corporation and Mid-Continent Market Center in the Wichita market.

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

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.

Shortages of crews could delay our operations, adversely affect our ability to increase our reserves and production and adversely affect our results of operations.

Wage increases and shortages in personnel in the future could increase our costs and/or restrict or delay our ability to drill wells and conduct our operations. Any delay in the drilling of new wells or significant increase in labor costs could adversely affect our ability to increase our reserves and production and could reduce our revenue and cash flow. Additionally, higher labor costs could cause certain of our projects to become uneconomic and therefore not be implemented or cause existing wells to become shut-in, reducing our production and adversely affecting our results of operations.

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

In the Cherokee Basin, as of December 31, 2009, we held oil and gas leases on approximately 516,184 net acres, of which 124,180 net acres (or 24%) 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 75,621 net acres are scheduled to expire before December 31, 2010. If these leases expire and are not renewed, we will lose the right to develop the related properties.

We hold oil and gas leases and development rights, by virtue of farm-out agreements or similar mechanisms, on 29,877 net acres in the Appalachian Basin 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. We are currently required to drill three gross gas wells by April 30, 2010 in order to maintain approximately 2,000 net acres. We must also drill an additional three gross gas wells by December 31, 2010 to maintain approximately an additional 6,000 net acres. Furthermore, we are currently required to drill an additional four gross wells in order to maintain 1,605 net acres in New York. The exact deadline for the drilling of these four wells is currently unclear, due to permitting delays caused by an environmental impact review being conducted by the state of New York. We may not be able to meet the drilling and payment obligations to earn or maintain all of this leasehold acreage.

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

Our management has specifically identified drilling locations for our future multi-year drilling activities on our existing acreage. We have identified, based on reserves as of December 31, 2009, approximately 590 gross proved undeveloped drilling locations and approximately 1,063 additional gross potential drilling locations in the Cherokee Basin and approximately 25 gross proved undeveloped drilling locations and approximately 415 additional gross potential drilling locations in the Appalachian Basin. These identified drilling locations represent a significant part of our future long-term development drilling program. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, gas prices, costs and drilling results. The assignment of proved reserves to these locations is based on the assumptions regarding gas prices in our December 31, 2009 reserve report. In addition, no proved reserves are assigned to any of the approximately 1,063 Cherokee Basin and 415 Appalachian Basin potential drilling locations we have identified and therefore, there exists greater uncertainty with respect to the likelihood of drilling and completing successful commercial wells at these potential drilling locations. Our final determination of whether to drill any of these drilling locations will be dependent upon the factors described above, our financial condition, our ability to obtain additional capital as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, it is possible that not all of the numerous drilling locations identified will be drilled within the timeframe specified in the reserve report or will ever be drilled, and we do not know if we will be able to produce gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could have a significant adverse effect on our financial condition and results of operations.

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

If an examination of the title history of a property reveals that an oil or gas lease or other developed rights has been purchased in error from a person who is not the owner of the mineral interest desired, our interest would substantially decline in value. In such an instance, the amount paid for such oil or gas lease or leases or other developed rights would be lost. It is management s practice, in acquiring oil and gas leases, or undivided interests in oil and gas 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 oil and gas 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 an oil or gas well, however, it is the normal practice in the oil and gas 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 oil or gas 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 natural 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. However, FERC regulation will still affect our gathering systems and the markets for our natural gas. FERC s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, could indirectly affect our gathering systems. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, FERC may not continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, 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.

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.

Third-party producers on our Cherokee Basin gathering system have the ability to file complaints challenging the rates that we charge. The rates must be just, reasonable, not unjustly discriminatory and not unduly preferential. If the KCC or the 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 the rates with respect to the wells that were the subject of the complaint. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. In the future, the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

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.

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:

- transportation of natural gas;
- rates, operating terms and conditions of service;
- the types of services KPC may offer to its customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- accounting and recordkeeping;
- commercial relationships and communications with affiliated companies involved in certain aspects of the natural gas business; and
- the 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. Specifically, FERC uses a discounted cash flow model that incorporates the use of proxy groups to develop a range of reasonable returns earned on equity interests in companies with corresponding risks. FERC then assigns a rate of return on equity within that range to reflect specific risks of that pipeline when compared to the proxy group 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.

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 Energy Policy Act of 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 Energy Policy Act of 2005, FERC has initiated a number of enforcement proceedings and imposed penalties on various regulated entities, including other interstate natural gas pipelines.

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. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, liability for natural resource damages or damages to third parties, and to a lesser extent, issuance of injunctions to limit or cease operations.

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

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of oil and natural gas, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring

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landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance.

We may face unanticipated water and other waste disposal costs.

We may be subject to regulation that restricts our ability to discharge water produced as part of our gas production operations. Productive zones frequently contain water that must be removed in order for the gas to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce gas in commercial quantities. The produced water must be transported from the lease and injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability.

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

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

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

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

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

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;

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improve data collection, integration and analysis;

repair and remediate the pipeline as necessary; and

implement preventive and mitigating actions.

We incurred costs of approximately $0.2 million in 2009 to complete all baseline assessments of the covered high consequence area integrity testing. We estimate we will incur approximately $1.5 million in 2010 to implement pipeline integrity management program testing along certain segments of natural gas pipelines. We also incurred costs of approximately $0.4 million in 2009 and expect to incur additional costs in 2010 to complete the last year of a Stray Current Survey resulting from a 2005 DOT audit. These costs may be significantly higher than what we have estimated or previously incurred due to the following factors:

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

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

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

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

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

Recent and future environmental laws and regulations, including additional federal and state restrictions on greenhouse gas emissions that may be passed in response to climate change concerns, may increase our capital and operating costs and also reduce the demand for the oil and natural gas we produce. The oil and gas industry is a direct source of certain GHG emissions, such as carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Specifically, in December 2009, EPA published a final rule, also known as the Endangerment Finding, finding that GHGs in the atmosphere endanger public health and welfare, and that emissions of GHGs from mobile sources cause or contribute to the GHG pollution. The Endangerment Finding took effect on January 14, 2010 and allows EPA to promulgate motor vehicle GHG emission standards. EPA is expected to promulgate such standards in March 2010. Motor vehicle emission standards could impact our operations by effectively reducing demand for motor fuels from crude oil. In addition, EPA has asserted that final motor vehicle GHG emission standards will trigger construction and operating permit requirements for large stationary sources, which could affect our operations and our ability to obtain air permits for new or modified facilities. Similarly, on June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The U.S. Senate is working on its own legislation for controlling and reducing emissions of GHGs in the United States. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur capital expenditures and increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce. At the state level, more than one-third of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. The California Global Warming Solutions Act of 2006, also known as AB 32, caps California s greenhouse gas emissions at 1990 levels by 2020, and the California Air Resources Board is currently developing mandatory reporting regulations and early action measures to reduce GHG emissions prior to January 1, 2012. Although most of the regulatory initiatives developed or being developed by the various states have to date been focused on large sources of GHG emissions, such as coal-fired electric power plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations in the future.

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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.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production in unconventional plays, which could adversely impact our revenues.

Congress is currently considering legislation to amend the SDWA to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells in the Appalachian Basin and specifically the Marcellus Shale. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level. This could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for us to perform hydraulic fracturing and increase our costs of compliance and doing business.

Growing our business by constructing new assets is subject to regulatory, political, legal and economic risks.

One of the ways we intend to grow our business in the long-term is through the construction of new midstream assets.

The construction of additions or modifications to our gas gathering systems and/or the KPC Pipeline, and the construction of new midstream assets, involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things:

- inability to complete construction of these projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials;
- failure to receive any material increases in revenues until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;
- facilities may be constructed to capture anticipated future growth in production in a region in which such growth does not materialize;
- reliance on third-party estimates of reserves in making a decision to construct facilities, which estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves;
- inability to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical;
- the construction of additions or modifications to the KPC Pipeline may require the issuance of certificates of public convenience and necessity from FERC, which may result in delays or increased costs; and

additions to or modifications of our gas gathering systems could result in a change in their NGA-exempt status.

Our ability to grow and to increase our profitability depends in part on our ability to make acquisitions. Our acquisition strategy is subject to a number of risks.

Our ability to grow and to increase our profitability depends 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 nevertheless result in a decrease in net income and/or cash flows. Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about reserves, future production, volumes, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- a decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management s and employees attention from other business concerns;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and investors will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

In addition, we may pursue acquisitions outside the Cherokee and Appalachian Basins. Because we operate substantially in the Cherokee and Appalachian Basins, we do not have the same level of experience in other basins.

Consequently, acquisitions in areas outside the Cherokee and Appalachian Basins may not allow us the same operational efficiencies we benefit from in those basins. In addition, acquisitions outside the Cherokee and Appalachian Basins expose us to different operational risks due to potential differences, among others, in:

- geology;
- well economics;
- availability of third-party services;
- transportation charges;

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- content, quantity and quality of oil and gas produced;
- volume of waste water produced;
- state and local regulations and permit requirements; and
- production, severance, ad valorem and other taxes.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume environmental and other risks and liabilities in connection with acquired properties.

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

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

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

Our interstate natural gas pipeline has recorded certain assets that may not be recoverable from our customers.

FERC rate-making and accounting policies permit pipeline companies to record certain types of expenses that relate to regulated activities to be recorded on our balance sheet as regulatory assets for possible future recovery in jurisdictional rates. We consider a number of factors to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable or if FERC denies recovery, we would be required to write off the regulatory assets at that time, potentially reducing our revenues.

Operational limitations of the KPC Pipeline could cause a significant decrease in our revenues and operating results.

During peak demand periods, failures of compression equipment or pipelines could limit the KPC Pipeline s ability to meet firm commitments, which may limit our ability to collect reservation charges from our customers and, if so, could negatively impact our revenues and results of operations.

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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 do have right-of-way and easement agreements from landowners and governmental agencies, some of which require annual payments to maintain the agreements and most of which have a perpetual term. New pipeline infrastructure construction may subject us to more onerous terms or to increased costs if the design of a pipeline requires redirecting. Such costs could have a material adverse effect on our business, results of operations and financial condition.

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

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

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

Risks Related to the Ownership of Our Common Stock

The price of our common stock may experience volatility.

The price of our common stock may 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.

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

We do not expect to pay dividends 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.

The value of the shares of our common stock may be diluted by future equity issuances.

No later than the first half of 2010, we will need to either refinance our debt to allow for available capital or raise a significant amount of equity capital to fund our drilling program and pay down outstanding indebtedness, including principal, interest and fees of approximately $21 million due under QRCP s credit agreement on July 11, 2010. Such issuance and sale of equity could be dilutive to the interests of our existing stockholders and reduce the market price of our common stock.

ITEM 1B. ***UNRESOLVED STAFF COMMENTS.***

None.

ITEM 2. ***PROPERTIES.***

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

Administrative Facilities

The office space for the corporate headquarters for us and our subsidiaries is leased and is located at 210 Park Avenue, Suite 2750, Oklahoma City, Oklahoma 73102. The office lease is for 10 years expiring August 31, 2017 covering approximately 35,000 square feet. We own four buildings within the vicinity of Chanute, Kansas that are used for administrative offices, a geological laboratory, an operations terminal and a repair facility. We own an additional building and storage yard in Lenapah, Oklahoma.

Our subsidiary Quest Eastern Resource LLC (Quest Eastern) has leased approximately 4,744 square feet of office space located at 2200 Georgetowne Drive, Suite 301, Sewickley, Pennsylvania 15143. Since administrative duties have been transferred to Oklahoma City, Quest Eastern is actively pursuing a sub-lease tenant for the remaining term of its lease, which expires on August 1, 2013. Quest Eastern also owns a 50% interest in a nine acre lot with building improvements in Wetzel County, West Virginia that is used for equipment storage and office space and leases approximately 1,500 square feet of office space for field personnel in Harrisville, West Virginia under an annual lease expiring on August 31, 2010.

We have 9,801 square feet of leased office space for some of our personnel located at 3 Allen Center, 333 Clay Street, Suite 4060, Houston, Texas 77002. The office lease expires on May 6, 2015.

We have leased facilities at Olathe, Wichita, and Medicine Lodge, Kansas for the operations of our interstate pipeline. The Olathe office consists of approximately 7,650 square feet for a lease term of five years expiring October 31, 2011. The Wichita office consists of approximately 1,240 square feet on an annual lease expiring December 31, 2010. 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. We are currently a defendant in the following litigation. We intend to defend vigorously against the claims described below. We are unable to predict the outcome of these proceedings or reasonably estimate a

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range of possible loss that may result. Like other oil and natural gas producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Therefore it is extremely difficult to reasonably quantify future environmental related expenditures.

Federal Securities Class Actions

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

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

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

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

Four putative class action complaints were filed in the United States District Court for the Western District of Oklahoma naming QRCP, QELP and QEGP and certain of their then current and former officers and directors as defendants. The complaints were filed by certain stockholders on behalf of themselves and other stockholders who purchased QRCP common stock between May 2, 2005 and August 25, 2008 and QELP common units between November 7, 2007 and August 25, 2008. The complaints assert claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as amended (the Exchange Act), and Rule 10b-5 promulgated thereunder, and Sections 11 and 15 of the Securities Act of 1933. The complaints allege that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material facts concerning certain unauthorized transfers of funds from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaints also allege that, as a result of these actions, QRCP s stock price and the unit price of QELP was artificially inflated during the class period. On December 29, 2008, the court consolidated these complaints as *Michael Friedman, individually and on behalf of all others similarly situated v. Quest Energy Partners LP, Quest Energy GP LLC, Quest Resource Corporation, Jerry Cash, and David E. Grose*, Case No. 08-cv-936-M, in the Western District of Oklahoma. On September 24, 2009, the court appointed lead plaintiffs for each of the QRCP class and the QELP class. On October 13, 2009, the plaintiffs filed a motion for partial modification of PSLRA discovery stay, which the defendants opposed and which the court denied on December 15, 2009. On November 4, 2009, the court granted the lead plaintiffs unopposed request to file separate consolidated amended complaints. The court ordered that all pleadings and filings for the QELP class be filed under *Friedman v. Quest Energy Partners, LP, et al.*, case no. CIV-08-936-M, and all pleadings and filings for the QRCP class be filed under *Jents v. Quest Resource Corporation, et al.*, case no. CIV-08-968-M. The QELP lead plaintiffs filed a consolidated complaint on November 10, 2009. The consolidated complaint names as additional defendants David C. Lawler, Gary Pittman, Mark Stansberry, Murrell Hall, McIntosh & Co. PLLP, and Eide Bailly LLP. The QRCP lead plaintiffs filed a consolidated complaint on December 7, 2009, which names Murrell, Hall, McIntosh & Co. PLLP, Eide Bailly LLP, and various former QRCP directors as additional defendants. On December 23, 2009, QRCP and David C. Lawler filed a motion to dismiss the *Friedman* complaint, and on December 28, 2009, QELP, QEGP, Gary Pittman and Mark Stansberry filed a motion to dismiss the *Friedman* complaint. On January 21, 2010, QRCP and the individual director defendants filed a motion to dismiss the *Jents* complaint. No response to the motion to dismiss has yet been filed in either proceeding. On February 2, 2010, a mediation was held among the parties. A second round of the mediation is currently scheduled for April 2, 2010. In the event that the cases are not settled, then the companies intend to defend vigorously against the plaintiffs claims in both the *Friedman* and *Jents* actions.

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QRCP and QELP have received letters from their directors and officers insurance carriers reserving their rights to limit or preclude coverage under various provisions and exclusions in the policies, including for the committing of a deliberate criminal or fraudulent act by a past, present, or future chief executive officer or chief financial officer. On October 27, 2009, QELP received written confirmation from its directors and officers liability insurance carrier stating that it will not provide insurance coverage to QELP based on Mr. Cash s alleged written admission that he engaged in acts for which coverage is excluded. The carrier also reserved its rights to deny coverage under various other provisions and exclusions in the policies. QELP disagrees with the insurance carrier s coverage position and continues to evaluate its options regarding the same.

Federal Individual Securities Litigation

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

On August 24, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma naming QRCP and certain then current and former officers and directors as defendants. The complaint was filed by an individual stockholder of QRCP. The complaint asserts claims under Sections 10(b) and 20(a) of the Exchange Act. The complaint alleges that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material information concerning unauthorized transfers from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaint also alleges that QRCP issued false and misleading statements and or/concealed material information concerning a misappropriation by its former chief financial officer, Mr. David E. Grose, of $1 million in company funds and receipt of unauthorized kickbacks of approximately $850,000 from a company vendor. The complaint also alleges that, as a result of these actions, QRCP s stock price was artificially inflated when the plaintiff purchased their shares of QRCP common stock. Plaintiffs have agreed to participate in the April 2, 2010 mediation mentioned above in connection with the federal securities class actions. QRCP intends to defend vigorously against the plaintiff s claims.

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

On November 3, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma naming QRCP, QELP, and certain then current and former officers and directors as defendants. The complaint was filed by individual shareholders of QRCP stock and individual purchasers of QELP common units. The complaint asserts claims under Sections 10(b) and 20(a) of the Exchange Act. The complaint alleges that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material information concerning unauthorized transfers from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaint also alleges that QRCP and QELP issued false and misleading statements and or/concealed material information concerning a misappropriation by its former chief financial officer, Mr. David E. Grose, of $1 million in company funds and receipt of unauthorized kickbacks of approximately $850,000 from a company vendor. The complaint also alleges that, as a result of these actions, the price of QRCP stock and QELP common units was artificially inflated when the plaintiffs purchased QRCP stock and QELP common units. The plaintiffs seek $10 million in damages. QRCP and QELP intend to defend vigorously against the plaintiffs claims. Plaintiffs have agreed to participate in the April 2, 2010 mediation mentioned above in connection with the federal securities class actions.

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Federal Derivative Cases

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

On September 25, 2008, a complaint was filed in the United States District Court for the Western District of Oklahoma, purportedly on QRCP s behalf, which named certain of QRCP s then current and former officers and directors as defendants. The factual allegations mirror those in the purported class actions described above, and the complaint asserts claims for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets, and unjust enrichment. The complaint seeks disgorgement, costs, expenses, and equitable and/or injunctive relief. On October 16, 2008, the court stayed this case pending the court s ruling on any motions to dismiss the class action claims. Proceedings in this matter are currently stayed. QRCP intends to defend vigorously against these claims.

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

On July 17, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma, purportedly on QELP s behalf, which named certain of its then current and former officers and directors, external auditors and vendors. The factual allegations relate to, among other things, the transfers and lack of effective internal controls. The complaint asserts claims for breach of fiduciary duty, waste of corporate assets, unjust enrichment, conversion, disgorgement under the Sarbanes-Oxley Act of 2002, and aiding and abetting breaches of fiduciary duties against the individual defendants and vendors and professional negligence and breach of contract against the external auditors. The complaint seeks monetary damages, disgorgement, costs and expenses and equitable and/or injunctive relief. It also seeks QELP to take all necessary actions to reform and improve its corporate governance and internal procedures. On September 8, 2009, the case was transferred to Judge Miles-LaGrange, who is presiding over the other federal cases, and the case number was changed to CIV-09-752-M. All proceedings in this matter are currently stayed under Judge Miles-LaGrange s order of October 16, 2009. QELP intends to defend vigorously against these claims.

State Court Derivative Cases

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

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

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

The factual allegations in these petitions mirror those in the purported class actions discussed above. All three petitions assert claims for breach of fiduciary duty, abuse of control, gross mismanagement, and unjust enrichment. The *Jacobson* petition also asserts claims against the two auditing firms named in that suit for

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professional negligence and aiding and abetting the director defendants breaches of fiduciary duties. The *Wulfert* petition also asserts a claim against Mr. Bryan Simmons for aiding and abetting Messrs. Cash s and Grose s breaches of fiduciary duties. The petitions seek damages, costs, expenses, and equitable relief. On March 26, 2009, the court consolidated these actions as *In re Quest Resource Corporation Shareholder Derivative Litigation*, Case No. CJ-2008-9042. Under the court s order, the defendants need not respond to the individual petitions. The action is stayed by agreement of the parties until the motions to dismiss in the pending federal securities class action litigation are decided. QRCP intends to defend vigorously against plaintiffs claims.

Royalty Owner Class Action

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

Quest Cherokee, a wholly-owned subsidiary of QELP, was named as a defendant in a class action lawsuit filed by several royalty owners in the U.S. District Court for the District of Kansas. The case was filed by the named plaintiffs on behalf of a putative class consisting of all Quest Cherokee s royalty and overriding royalty owners in the Kansas portion of the Cherokee Basin. Plaintiffs contend that Quest Cherokee failed to properly make royalty payments to them and the putative class by, among other things, paying royalties based on reduced volumes instead of volumes measured at the wellheads, by allocating expenses in excess of the actual costs of the services represented, by allocating production costs to the royalty owners, by improperly allocating marketing costs to the royalty owners, and by making the royalty payments after the statutorily proscribed time for doing so without providing the required interest. Quest Cherokee has answered the complaint and denied plaintiffs claims. On July 21, 2009, the court granted plaintiffs motion to compel production of Quest Cherokee s electronically stored information, or ESI, and directed the parties to decide upon a timeframe for producing Quest Cherokee s ESI. Discovery was stayed until April 14, 2010 to allow the parties to discuss settlement terms.

Litigation Related to Oil and Gas Leases

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

QRCP *et al.* have been named in the above-referenced lawsuit. Plaintiffs are royalty owners who allege that the defendants have wrongfully deducted costs from the royalties of plaintiffs and have engaged in self-dealing contracts resulting in less than market price for the gas production. Plaintiffs pray for unspecified actual and punitive damages. The defendants have filed a motion to dismiss certain tort claims, but no ruling has yet been issued by the Court. Limited pretrial discovery has occurred. No court deadlines have been set. QRCP intends to defend vigorously against the plaintiffs claims.

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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. There were no daily high and low sales prices per share or cash distributions to PostRock stockholders during 2009 or 2008. The closing price for our common stock on March 8, 2010 was $16.36 per share.

As of March 8, 2010, there were 8,029,898 shares of common stock outstanding held of record by approximately 672 stockholders.

Dividends

The payment of dividends on our common stock is within the discretion of the board of directors and will depend on our earnings, capital requirements, financial condition and other relevant factors. We have not declared any cash dividends on our common stock and do not anticipate paying any dividends on our common stock in the foreseeable future. Our ability to pay dividends on our common stock is subject to restrictions contained in our credit agreements. See Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Agreements for a discussion of these restrictions.

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

None.

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ITEM 6. *SELECTED FINANCIAL DATA (PREDECESSOR).*

We have derived the following selected consolidated financial information as of December 31, 2009 and 2008, and for the years ended December 31, 2009, 2008 and 2007, from the audited consolidated financial statements of QRCP (predecessor to PostRock) included in Part II, Item 8 of this Annual Report on Form 10-K. We have derived the selected consolidated financial information as of December 31, 2007, 2006 and 2005 and for the years ended December 31, 2006 and 2005 from the consolidated financial information of QRCP included in QRCP s annual report on Form 10-K/A for the year ended December 31, 2008 recasted to conform with the presentation requirements of FASB ASC 810 regarding noncontrolling interests. The selected consolidated financial information below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of this Annual Report on Form 10-K and the audited consolidated financial statements and related notes included in Part II, Item 8 of this Annual Report on Form 10-K.

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except share and per share data)				
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$ 79,893	$ 162,499	$ 105,285	$ 72,410	$ 70,628
Gas pipeline revenue	26,188	28,176	9,853	5,014	3,939
Total revenues	106,081	190,675	115,138	77,424	74,567
Costs and expenses:					
Oil and gas production	33,451	44,111	36,295	25,338	18,532
Pipeline operating	29,083	29,742	21,098	13,151	7,703
General and administrative	41,723	28,269	21,023	8,655	6,218
Depreciation, depletion and amortization	47,802	70,445	39,782	27,011	22,244
Impairments	268,630	298,861			
Loss (Recovery) from misappropriation of funds	(3,412)		2,000	6,000	2,000
Total costs and expenses	417,277	471,428	120,198	80,155	56,697
Operating income (loss)	(311,196)	(280,753)	(5,060)	(2,731)	17,870
Other income (expense):					
Gain (loss) from derivative financial instruments	48,122	66,145	1,961	52,690	(73,566)
Gain (loss) on sale of assets		24	(322)	3	12
Loss on early extinguishment of debt					(12,355)
Other income (expense)	83	305	(9)	99	389
Interest expense, net	(29,329)	(25,373)	(43,628)	(20,567)	(28,225)
Total other income and (expense)	18,876	41,101	(41,998)	32,225	(113,745)

Income (loss) before income taxes		(292,320)		(239,652)		(47,058)		29,494		(95,875)
Income tax benefit (expense)										
Net income (loss)		(292,320)		(239,652)		(47,058)		29,494		(95,875)
Net loss attributable to noncontrolling interests		147,398		72,268		2,904		14		
Net income (loss) attributable to common stockholders		(144,922)		(167,384)		(44,154)		29,508		(95,875)
Preferred stock dividends										(10)
Net income (loss) available to common shareholders	$	(144,922)	$	(167,384)	$	(44,154)	$	29,508	$	(95,885)
Net income (loss) available to common shareholders per share:										
Basic and diluted	$	(4.55)	$	(6.20)	$	(1.97)	$	1.33	$	(11.48)
Weighted average common and common equivalent shares outstanding:										
Basic and diluted		31,833,222		27,010,690		22,379,479		22,119,497		8,351,945
Balance Sheet Data (at end of period):										
Total assets	$	283,655	$	650,176	$	672,537	$	467,936	$	274,768
Long-term debt, net of current maturities	$	19,295	$	343,094	$	233,046	$	225,245	$	100,581

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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, (3) the formation of QMLP in December 2006, (4) the acquisition of the KPC Pipeline on November 1, 2007, (5) QELP s initial public offering effective November 15, 2007, (6) the PetroEdge acquisition in July 2008, (7) investigation and litigation costs associated with the misappropriation by our former chief executive officer and chief financial officer in 2008 and 2009, (8) expenses related to the recombination in 2009 and (9) impairment of oil and gas 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 pipelines of $165.7 million in 2009.

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

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

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 natural gas properties and related pipeline infrastructure; timing and amount of future production of oil and natural gas; operating costs and other expenses; estimated future net revenues from oil and natural gas reserves and the present value thereof; cash flow and anticipated liquidity; funding of our capital expenditures; ability to meet our debt service obligations; and other plans and objectives for future operations.

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

- current weak economic conditions;
- our current financial condition and liquidity constraints;
- volatility of oil and natural gas prices;
- benefits or effects of the recombination;
- increases in the cost of drilling, completion and gas gathering or other costs of developing and producing our reserves;
- our restrictive 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.

Overview of Our Company

We are a Delaware corporation formed on July 1, 2009 solely for the purpose of effecting a recombination of QRCP, QELP and QMLP. Prior to the consummation of the recombination on March 5, 2010, we did not conduct any business operations other than incidental to our formation and in connection with the transactions contemplated by the merger agreement for the recombination. Following the recombination, we own QRCP, QELP and QMLP as direct or indirect wholly-owned subsidiaries and have no significant assets other than the stock and other voting securities of our subsidiaries.

We are an integrated independent energy company involved in the acquisition, development, exploration, production and transportation of natural gas, primarily from coal seams (coal bed methane, or CBM) and unconventional shale, and oil and natural gas from conventional reservoirs. We conduct our business through two reportable business segments:

- Oil and natural gas production, and
- Natural gas pipelines, including transporting, gathering, treating and processing natural gas.

Our principal operations and producing properties are located in the Cherokee Basin of southeastern Kansas and northeastern Oklahoma; Central Oklahoma; and West Virginia, Pennsylvania and New York in the Appalachian Basin. Our primary assets, as of December 31, 2009, consisted of natural gas wells, oil wells, development rights and natural gas gathering pipelines in the Cherokee Basin and Appalachian Basin, oil and natural gas wells and development rights in Central Oklahoma, and an interstate natural gas pipeline that transports natural gas from northern Oklahoma and western Kansas to the metropolitan Wichita and Kansas City markets.

Operating Highlights

Our significant operational highlights in 2009 include:

- Reduced oil and natural gas production costs to $1.54 per Mcfe (including production and property taxes of $0.35 per Mcfe) in 2009 from $2.03 per Mcfe (including production and property taxes of $0.45 per Mcfe) in 2008, which reduced operating costs by $10.6 million.
- Sustained a production level of 21.7 MMcfe in 2009 despite minimal current period capital expenditures on acquisition and development.

Cost-cutting Measures.

We successfully reduced our operating costs in 2009 through the implementation of process improvement initiatives. These initiatives support our efficient operating model that seeks to generate the highest production possible for the lowest sustainable cost. In addition to process improvement initiatives, we have employed the latest artificial lift technology in order to improve equipment reliability and minimize costly wellbore interventions. We have also optimized our compression fleet to decrease fuel consumption and improve horsepower utilization. We periodically evaluate all aspects of our operation to further reduce our costs.

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Material Events and Transactions

The following events or transactions impacted our results of operations in 2009:

Pipeline segment impairment

Certain events during the fourth quarter of 2009 indicated our pipeline assets and intangibles could be impaired. We were unable to negotiate a new contract with one of our major customers for the KPC Pipeline, MGE. Our existing contract with MGE expired in October 2009, although prior to the expiration we believed that the contract could be extended or renegotiated with MGE or replaced by another customer. In addition, while we were successful in negotiating amendments to our credit facilities in December 2009, the amended credit facilities imposed limits on our capital expenditures and consequently on our ability to further develop acreage in the Cherokee Basin, the geographic region served by our gathering system. This reduced the future projected revenues of the gathering system.

Based on our analysis, we determined that the carrying value of our pipeline assets exceeded their fair values by approximately $164.7 million and recorded an impairment for such amount in the fourth quarter of 2009. In addition, we determined that our customer-related contracts, held by KPC and presented as intangible assets on the balance sheet, were also impaired. We recognized an impairment of $1.0 million on our intangible assets. No such impairment was required at December 31, 2008.

Oil and natural gas impairment

Prior to December 31, 2009, full cost accounting rules required us to compute the after-tax present value of our proved oil and natural gas properties using spot market prices for oil and natural gas at our balance sheet date. Beginning with this annual report, a twelve-month average is now used. The base for our spot prices for natural gas is Henry Hub and for oil is Cushing, Oklahoma. At the end of the first quarter of 2009, we recorded a ceiling test impairment of $102.9 million. At the end of the third quarter of 2009, the ceiling test computation resulted in the carrying costs of our unamortized proved oil and natural gas properties, net of deferred taxes, exceeding the September 30, 2009 present value of future net revenues by approximately $11.1 million. As a result of subsequent increases in spot prices, the need to recognize an impairment for the quarter ended September 30, 2009 was eliminated. No further impairment was necessary for the remainder of 2009.

Settlement of misappropriation

In May 2009, QRCP, QELP and QMLP entered into settlement agreements with Mr. Cash, a controlled entity of Mr. Cash and the other owners of the controlled entity to settle litigation related to the misappropriation of funds discussed under Part I, Item 1A. Risk Factors Risks Related to Our Business Former senior management were terminated in 2008 following the discovery of various misappropriations of funds of QRCP and QELP. Under the terms of the settlement agreements, we received (1) approximately $2.4 million in cash and (2) 60% of the controlled entity s interest in a natural gas well located in Louisiana and a landfill natural gas development project located in Texas. We also received all of Mr. Cash s equity interest in STP Newco, Inc. (STP), which owns certain oil producing properties in Oklahoma, and other assets as reimbursement for costs of the internal investigation and the litigation against Mr. Cash that we have paid. We have estimated the fair value of the assets and liabilities obtained in connection with the settlement to be $3.4 million.

Increased Costs

We experienced significant increased general and administrative costs in 2009 due to various factors, such as the internal investigation and our responding to inquiries with respect to the misappropriation of funds by our former chief executive officer and chief financial officer. As a result of the termination of the former chief executive officer and chief financial officer, we retained consultants to perform the accounting and finance functions. We incurred legal expenses in connection with responses to the class action and derivative suits that have been filed against us and to pursue the claims against the former employees. Our audit expenses were

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higher as a result of retaining new auditors to complete reaudits of the restated consolidated financial statements for the years ended December 31, 2007, 2006 and 2005. In connection with our recombination, we retained financial advisors, accountants, other consultants and outside legal counsel as well as incurred other costs related to the SEC registration process and the shareholder and unitholder meetings to approve the recombination. These activities contributed to the increase in our general and administrative costs by approximately $13.4 million in 2009 compared to 2008.

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 include the following: (1) volumes of gas and oil produced; (2) quantity of proved reserves; (3) realized prices; (4) throughput volumes, firm transportation contracted volumes, fuel consumption by our facilities and natural gas sales volumes; (5) operations and maintenance expenses; and (6) oil and gas production and general and administrative expenses.

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 $4.06 per Mcf in 2009, and the forecast price averages $5.36 per Mcf in 2010 and $6.12 per Mcf in 2011. Continued high storage levels, combined with enhanced domestic production capabilities and slow consumption growth, are expected to keep prices from rising dramatically through the forecast.

Oil and natural gas prices historically have been very volatile and will likely continue to be so in the future. While natural gas inventories remain ample, implied volatility for the futures market in natural gas options moved slightly higher at the start of 2010. Implied volatility for options settling against March 2010 natural gas futures averaged just below 57%, similar to the prior year when implied volatility on the March 2009 natural gas options was at 59%.

We sell the majority of our natural 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 2009, the discount (or basis differential) in the Cherokee Basin ranged from $0.05/Mmbtu to $(1.37)/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 Natural Gas

The EIA estimates that total natural gas consumption fell by 1.5 percent in 2009, primarily because of the economic downturn. Despite low natural gas prices throughout most of 2009, which contributed to a significant increase in natural gas-fired electric power generation, declines in industrial, residential, and commercial sector consumption drove the year-over-year decline in total consumption. Total annual natural gas consumption is forecast to remain relatively unchanged in 2010. Higher natural gas prices in 2010 are expected to cause a 2.8 percent decline in natural gas consumption in the electric power sector in 2010, which will offset growth in the residential, commercial, and industrial sectors. Forecast total natural gas consumption increases by 0.4 percent in 2011, led by a 2.5 percent increase in consumption in the industrial sector.

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The world oil market is expected to gradually tighten in 2010 and 2011, provided the global economic recovery continues as projected. Although compliance with cuts announced by the Organization of the Petroleum Exporting Countries (OPEC) has weakened and global oil inventories and spare production capacity remain very high by historical standards, expectations of a continued global economic turnaround have continued to buttress oil markets. Global oil demand declined in 2009 for the second consecutive year. The decline bottomed out in the middle of 2009, as the world economy began to recover in the last half of the year. EIA expects this recovery to continue in 2010 and 2011, contributing to global oil demand growth of 1.1 million barrels per day (Bbl/d) in 2010 and 1.5 million Bbl/d in 2011. In the United States, projected demand is expected to increase slightly by 0.2 million Bbl/d after a very weak 2009.

Capital Constraints

Due to the global economic and financial crisis, weak commodity prices, the unauthorized transfers of funds by prior senior management and restrictions in our credit agreements, we have not been able to raise the capital necessary to implement our drilling plans for 2009 and 2010. For 2010, we have budgeted approximately $6.0 million to complete and $5.5 million to connect 108 gross wells that were previously drilled but not completed, and $2.7 million for land and equipment in the Cherokee Basin. In the Appalachian Basin, for 2010 we have budgeted approximately $20 million of net expenditures to drill and complete three vertical wells and six horizontal wells and $2.5 million on land, equipment and connections. We intend to fund these capital expenditures with available cash from operations after taking into account our debt service obligations and with the proceeds of additional equity capital issuances and borrowings, but there can be no assurance that we will be able to obtain the capital to achieve this plan.

Results of Operations

The following discussion of results of operations should be read in conjunction with the audited consolidated financial statements and the notes to the consolidated financial statements of the predecessor, which are included elsewhere in this Annual Report on Form 10-K.

	2009	2008	2007
		(In thousands)	
Revenues:			
Oil and gas production	$ 79,893	$ 162,499	$ 105,285
Natural gas pipelines	67,323	63,722	39,032
Elimination of inter-segment revenue	(41,135)	(35,546)	(29,179)
Natural gas pipelines, net of inter-segment revenue	26,188	28,176	9,853
Total segment revenues	$ 106,081	$ 190,675	$ 115,138
Operating profit (loss):			
Oil and gas production(a)	$ (129,788)	$ (269,729)	$ 5,999
Natural gas pipelines(b)	(143,097)	17,245	11,964
Total segment operating profit (loss)	(272,885)	(252,484)	17,963
General and administrative expenses	41,723	28,269	21,023
Loss (Recovery) from misappropriation of funds	(3,412)		2,000

Total operating income (loss)	$ (311,196)	$ (280,753)	$ (5,060)

(a) Includes impairment of oil and gas properties of $102.9 million and $298.9 million in 2009 and 2008, respectively.

(b) Includes impairment of pipeline related assets of $165.7 million in 2009.

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

Oil and Gas Production Segment

	Year Ended December 31, 2009	Year Ended December 31, 2008	Increase/ (Decrease)	
	($ in thousands)			
Oil and gas sales	$ 79,893	$ 162,499	$ (82,606)	(50.8)%
Oil and gas production costs	$ 33,451	$ 44,111	$ (10,660)	(24.2)%
Transportation expense (intercompany)	$ 41,135	$ 35,546	$ 5,589	15.7%
Depreciation, depletion and amortization	$ 32,193	$ 53,710	$ (21,517)	(40.1)%
Impairment charge of oil and natural gas properties	$ 102,902	$ 298,861	$ (195,959)	(65.6)%

Production. The following table presents the primary components of revenues of our Oil and Gas Production Segment (oil and natural gas production and average oil and natural gas prices), as well as the average costs per Mcfe, for the fiscal years ended December 31, 2009 and 2008.

	Year Ended December 31, 2009	Year Ended December 31, 2008	Increase/ (Decrease)	
Production Data:				
Total production (Mmcfe)	21,733	21,748	(15)	(0.1)%
Average daily production (Mmcfe/d)	59.5	59.4	0.1	0.2%
Average Sales Price per Unit (Mcfe)	$ 3.68	$ 7.47	$ (3.79)	(50.7)%
Average Unit Costs per Mcfe:				
Production costs	$ 1.54	$ 2.03	$ (0.49)	(24.1)%
Transportation expense (intercompany)	$ 1.89	$ 1.63	$ 0.26	16.0%
Depreciation, depletion and amortization	$ 1.48	$ 2.47	$ (0.99)	(40.1)%

Oil and Gas Sales. Oil and gas sales decreased $82.6 million, or 50.8%, to $79.9 million for the year ended December 31, 2009 from $162.5 million for the year ended December 31, 2008. This decrease was primarily the result of a decrease in average realized sales prices of $82.5 million coupled with a minimal decrease in volumes accounting for $0.1 million of the decrease. Our average realized prices, which exclude hedge settlements, on an equivalent basis (Mcfe) decreased to $3.68 per Mcfe for the year ended December 31, 2009 from $7.47 per Mcfe for the year ended December 31, 2008.

Oil and Gas Operating Expenses. Oil and gas operating expenses consist of oil and gas production costs, which include lease operating expenses, severance and ad valorem taxes, and transportation expense. Oil and gas operating expenses decreased $5.1 million, or 6.4%, to $74.6 million during the year ended December 31, 2009, from $79.7 million during the year ended December 31, 2008.

Oil and gas production costs decreased $10.7 million, or 24.2%, to $33.4 million during the year ended December 31, 2009, from $44.1 million during the year ended December 31, 2008. This decrease was achieved through process improvement measures discussed above under Operating Highlights Cost-cutting Measures. Production costs, including gross production taxes and ad valorem taxes, were $1.54 per Mcfe for the year ended December 31, 2009 as compared to $2.03 per Mcfe for the year ended December 31, 2008.

Transportation expense increased $5.6 million, or 15.7%, to $41.1 million during the year ended December 31, 2009, from $35.5 million during the year ended December 31, 2008. The increase was primarily due to the increase in the contracted rate charged by our Cherokee Basin gathering pipeline in 2009 compared to 2008. The per unit cost increased $0.26 per Mcfe to $1.89 per Mcfe for the year ended December 31, 2009 as compared to $1.63 per Mcfe for the year ended December 31, 2008.

Depreciation, Depletion and Amortization. We are subject to variances in our depletion rates from period to period due to changes in our oil and natural gas reserve quantities, production levels, product prices and changes in the depletable cost basis of our oil and natural gas properties. Our depreciation, depletion and amortization decreased approximately $21.5 million, or 40.1%, during the year ended December 31, 2009 to $32.2 million from $53.7 million during the year ended December 31, 2008. On a per unit basis, we had a decrease of $0.99 per Mcfe to $1.48 per Mcfe during the year ended December 31, 2009 from $2.47 per Mcfe during the year ended December 31, 2008. This decrease was primarily due to the impairments of our oil and gas properties in the fourth quarter of 2008 and the first quarter of 2009, which decreased our rate per unit, as well as the resulting decrease in the depletable pool.

Impairment of Oil and Natural Gas Properties. We recorded an impairment of oil and natural gas properties of $102.9 million during the first quarter of 2009. See Operating Highlights Material Events and Transactions Oil and natural gas impairment above. We recognized impairments of our oil and natural gas properties of $298.9 million for 2008.

Natural Gas Pipelines Segment

	Year Ended December 31, 2009	Year Ended December 31, 2008	Increase/(Decrease)	
	($ in thousands, except per Mcf data)			
Natural Gas Pipeline Revenue:				
Gas pipeline revenue Third Party	$ 26,188	$ 28,176	$ (1,988)	(7.1)%
Gas pipeline revenue Intercompany	$ 41,135	$ 35,546	$ 5,589	15.7%
Total natural gas pipeline revenue	$ 67,323	$ 63,722	$ 3,601	5.7%
Pipeline operating expense	$ 29,083	$ 29,742	$ (659)	(2.2)%
Depreciation and amortization expense	$ 15,609	$ 16,735	$ (1,126)	(6.7)%
Impairment of long-lived assets	$ 165,728	$	$ 165,728	*%
Throughput Data (Mcf):				
Throughput Third Party	11,095	11,111	(16)	(0.1)%
Throughput Intercompany	24,510	25,390	(880)	(3.5)%
Total throughput (Mcf)	35,605	36,501	(896)	(2.5)%
Average Pipeline Operating Costs per Mcf:				
Pipeline operating expense	$ 0.82	$ 0.81	$ 0.01	1.2%
Depreciation and amortization	$ 0.44	$ 0.46	$ (0.02)	(4.3)%

* Not meaningful

Pipeline Revenue. Total natural gas pipeline revenue increased $3.6 million, or 5.7%, to $67.3 million during the year ended December 31, 2009, from $63.7 million during the year ended December 31, 2008.

Third party natural gas pipeline revenue decreased $2.0 million, or 7.1%, to $26.2 million during the year ended December 31, 2009, from $28.2 million during the year ended December 31, 2008. The decrease was primarily due to the loss of a significant customer, MGE, as well as a renewal of certain contracts with another customer, KGS, at lower volumes and rates.

Intercompany natural gas pipeline revenue increased $5.6 million, or 15.7%, to $41.1 million during the year ended December 31, 2009, from $35.5 million during the year ended December 31, 2008. The increase was primarily due to the increase in the contracted rate charged by our Cherokee Basin gathering pipeline in 2009 compared to 2008.

Pipeline Operating Expense. Pipeline operating expense was generally flat, decreasing $0.6 million, or 2.2%, to $29.1 million during the year ended December 31, 2009 from $29.7 million during the year ended December 31, 2008. Pipeline operating costs per unit increased $0.01 per Mcf, from $0.81 per Mcf for the year ended December 31, 2008 to $0.82 per Mcf for the year ended December 31, 2009.

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Depreciation and Amortization. Depreciation and amortization expense decreased $1.1 million, or 6.7%, to $15.6 million during the year ended December 31, 2009, from $16.7 million during the year ended December 31, 2008.

Impairment of Long-lived Assets. During the fourth quarter of 2009, we recorded an impairment of $165.7 million on our pipeline assets and related intangibles. See Operating Highlights Material Events and Transactions Pipeline segment impairment above. No such impairment was required in 2008.

Unallocated Items

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

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

Interest expense, net. Interest expense, net, increased $3.9 million, or 15.6%, to $29.3 million during the year ended December 31, 2009, from $25.4 million during the year ended December 31, 2008. The increase is primarily due to $3.5 million in write-offs of unamortized debt issuance cost associated with the modification of our credit agreements in 2009. See Liquidity and Capital Resources Sources of Liquidity in 2009 and Capital Requirements Credit Agreements below.

Recovery from Misappropriation of Funds. We recorded a recovery of misappropriated funds of $3.4 million for 2009. See Operating Highlights Material Events and Transactions Settlement of misappropriation above.

Year ended December 31, 2008 compared to the year ended December 31, 2007

Oil and Gas Production Segment

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase/ (Decrease)	
	($ in thousands)			
Oil and gas sales	$ 162,499	$ 105,285	$ 57,214	54.3%
Oil and gas production costs	$ 44,111	$ 36,295	$ 7,816	21.5%
Transportation expense (intercompany)	$ 35,546	$ 29,179	$ 6,367	21.8%
Depreciation, depletion and amortization	$ 53,710	$ 33,812	$ 19,898	58.8%
Impairment of oil and gas properties	$ 298,861	$	$ 298,861	*%

* Not meaningful

Production. The following table presents the primary components of revenues of our Oil and Gas Production Segment (oil and natural gas production and average oil and natural gas prices), as well as the average costs per Mcfe, for the fiscal years ended December 31, 2008 and 2007.

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase/ (Decrease)	
Production Data:				
Total production (Mmcfe)	21,748	17,017	4,731	27.8%
Average daily production (Mmcfe/d)	59.4	46.6	12.8	27.5%
Average Sales Price per Unit (Mcfe)	$ 7.47	$ 6.19	$ 1.28	20.7%
Average Unit Costs per Mcfe:				
Production costs	$ 2.03	$ 2.13	$ (0.10)	(4.7)%
Transportation expense (intercompany)	$ 1.63	$ 1.71	$ (0.08)	(4.7)%
Depreciation, depletion and amortization	$ 2.47	$ 1.99	$ 0.48	24.1%

Oil and Gas Sales. Oil and gas sales increased $57.2 million, or 54.3%, to $162.5 million during the year ended December 31, 2008. This increase was the result of increased sales volumes and an increase in average realized prices. Additional volumes of 4,731 Mmcfe accounted for $32.2 million of the increase. The increased volumes resulted from additional wells completed in 2008. The remaining increase of $25.0 million was attributable to an increase in the average product price in 2008. Our average product prices, which exclude hedge settlements, on an equivalent basis (Mcfe) increased to $7.47 per Mcfe for the 2008 period from $6.19 per Mcfe for the 2007 period.

Oil and Gas Operating Expenses. Oil and gas operating expenses consist of oil and gas production costs, which include lease operating expenses, severance and ad valorem taxes, and transportation expense. Oil and gas operating expenses increased $14.2 million, or 21.7%, to $79.7 million during the year ended December 31, 2008, from $65.5 million during the year ended December 31, 2007.

Oil and gas production costs increased $7.8 million, or 21.5%, to $44.1 million during the year ended December 31, 2008, from $36.3 million during the year ended December 31, 2007. This increase was primarily due to increased volumes in 2008. Production costs including gross production taxes and ad valorem taxes were $2.03 per Mcfe for the year ended December 31, 2008 as compared to $2.13 per Mcfe for the year ended December 31, 2007. The decrease in per unit cost was due to higher volumes over which to spread fixed costs.

Transportation expense increased $6.4 million, or 21.8%, to $35.5 million during the year ended December 31, 2008, from $29.2 million during the year ended December 31, 2007. The increase was primarily due to increased volumes, which resulted in additional expense of approximately $7.6 million. This increase was offset by a decrease in per unit cost of $0.08 per Mcfe. Transportation expense was $1.63 per Mcfe for the year ended December 31, 2008 as compared to $1.71 per Mcfe for the year ended December 31, 2007. This decrease in per unit cost was due to increased volumes, over which to spread fixed costs.

Depreciation, Depletion and Amortization. We are subject to variances in our depletion rates from period to period due to changes in our oil and gas reserve quantities, production levels, product prices and changes in the depletable cost basis of our oil and gas properties. Our depreciation, depletion and amortization increased approximately $19.9 million, or 58.8%, in 2008 to $53.7 million from $33.8 million in 2007. On a per unit basis, we had an increase of $0.48 per Mcfe to $2.47 per Mcfe in 2008 from $1.99 per Mcfe in 2007. This increase was primarily due to downward revisions in our proved reserves, resulting in an increase in the per unit rate. In addition, depreciation and amortization increased approximately $5.5 million primarily due to additional vehicles, equipment and facilities acquired in 2008.

Impairment of Oil and Gas Properties. We recognized impairments of our oil and gas properties of $298.9 million for the year ended December 31, 2008. Under full cost method accounting, we are required to compute the after-tax present value of our proved oil and gas properties using spot market prices for oil and gas at our balance sheet date. The base for our spot prices for gas is Henry Hub. On December 31, 2008, the spot price for gas at Henry Hub was $5.71 per Mmbtu and the spot oil price was $44.60 per Bbl compared to $6.43 per Mmbtu and $92.01 per barrel, at December 31, 2007.

Natural Gas Pipelines Segment

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase/(Decrease) ($ in thousands)	
Natural Gas Pipeline Revenue:				
Gas pipeline revenue Third Party	$ 28,176	$ 9,853	$ 18,323	186.0%
Gas pipeline revenue Intercompany	$ 35,546	$ 29,179	$ 6,367	21.8%
Total natural gas pipeline revenue	$ 63,722	$ 39,032	$ 24,690	63.3%
Pipeline operating expense	$ 29,742	$ 21,098	$ 8,644	41.0%
Depreciation and amortization expense	$ 16,735	$ 5,970	$ 10,765	180.3%
Throughput Data (Mcf):				
Throughput Third Party	11,111	1,686	9,425	559.0%
Throughput Intercompany	25,390	17,148	8,242	48.1%
Total throughput (Mcf)	36,501	18,834	17,667	93.8%
Average Pipeline Operating Costs per Mcf:				
Pipeline operating expense	$ 0.81	$ 1.12	$ (0.31)	(27.7)%
Depreciation and amortization	$ 0.46	$ 0.32	$ 0.14	43.8%

Pipeline Revenue. Total natural gas pipeline revenue increased $24.6 million, or 63.3%, to $63.7 million during the year ended December 31, 2008, from $39.0 million during the year ended December 31, 2007.

Third-party natural gas pipeline revenue increased $18.3 million, or 186.0%, to $28.2 million during the year ended December 31, 2008, from $9.9 million during the year ended December 31, 2007. The increase was primarily related to the KPC Pipeline, which was acquired November 1, 2007. During the year ended December 31, 2008, the KPC Pipeline had revenues of $19.5 million compared to $3.2 million for the period from November 1, 2007 through December 31, 2007. The remaining increase of $2.0 million was due to additional third-party volumes on our gathering system.

Intercompany natural gas pipeline revenue increased $6.4 million, or 21.8%, to $35.5 million during the year ended December 31, 2008, from $29.2 million during the year ended December 31, 2007. The increase is due to the 48.1% increase in throughput volumes from our Cherokee Basin properties and the higher gathering and compression fees resulting from the midstream services agreement that became effective January 1, 2008.

Pipeline Operating Expense. Pipeline operating expense increased $8.6 million, or 41.0%, to $29.7 million during the year ended December 31, 2008, from $21.1 million during the year ended December 31, 2007. This increase is primarily the result of our acquisition of the KPC Pipeline in November 2007. Therefore, 2007 only had two months of expenses versus 12 months in 2008. During the year ended December 31, 2008, the KPC Pipeline had operating costs of $7.7 million compared to operating costs of $1.1 million during the period from November 1, 2007 through December 31, 2007. The remaining increase of $2.0 million is due to increased throughput volumes in 2008. Pipeline operating costs per unit decreased $0.31 per Mcf during 2008, from $1.12 per Mcf to $0.81 per Mcf. The decrease in per unit cost was the result of higher volumes, over which to spread fixed costs, as well as our cost-cutting efforts implemented in the third quarter of 2008.

Depreciation and Amortization. Depreciation and amortization expense increased $10.8 million, or 180.3%, to $16.7 million during the year ended December 31, 2008, from $6.0 million during the year ended December 31, 2007. The increase is primarily due to the amortization of our intangibles of $4.3 million acquired in the KPC Pipeline acquisition, as well as an increase in depreciation on our pipelines of $1.7 million. During the year ended December 31, 2008, the KPC Pipeline had depreciation and amortization expense of $5.6 million compared to $0.8 million for the period from November 1, 2007 through December 31,

2007. The remaining increase is due to the additional natural gas gathering pipeline installed during the year ended December 31, 2008.

Unallocated Items

General and Administrative Expenses. General and administrative expenses increased $7.2 million, or 34.5%, to $28.3 million during the year ended December 31, 2008, from $21.0 million during the year ended December 31, 2007. The increase is primarily due to the internal investigation and restatements and reaudits ($4.7 million), increased rent in connection with establishing a Houston office and new corporate headquarters ($1.7 million), the inclusion of the KPC Pipeline for all of 2008 compared to two months in 2007 ($2.5 million), and headcount (7%) and salary (10%) increases to support the growth of our company ($0.8 million). These amounts were partially offset by lower stock compensation expense ($3.9 million) in connection with the departure of QRCP s and QELP s former chief executive and financial officers. The remaining increase was the result of the costs associated with QELP being a separate publicly traded company.

Loss from Misappropriation of Funds. In connection with the unauthorized transfers of funds by certain former executives of QRCP and QELP, we recorded a loss from misappropriation of funds of $2.0 million for the year ended December 31, 2007.

Other Income (Expense). Gain from derivative financial instruments increased $64.1 million to $66.1 million during the year ended December 31, 2008, from $2.0 million during the year ended December 31, 2007. Due to the decline in average natural gas and crude oil prices during the second half of 2008, we recorded a $72.5 million unrealized gain and $6.4 million realized loss on our derivative contracts for the year ended December 31, 2008 compared to a $5.3 million unrealized loss and $7.3 million realized gain for the year ended December 31, 2007. Unrealized gains are attributable to changes in natural gas prices and volumes hedged from one period end to another.

Interest Expense, net. Interest expense, net decreased $18.3 million, or 41.8%, to $25.4 million during the year ended December 31, 2008, from $43.6 million during the year ended December 31, 2007. The decreased interest expense for the year ended December 31, 2008 relates to the write-off of $9.9 million of deferred debt issuance costs recorded in connection with the refinancing of our credit facilities during 2007 and lower interest rates during 2008.

Liquidity and Capital Resources

Our significant financial highlights as of December 31, 2009 include:

Reduced total debt by $58.8 million from December 31, 2008.

Increased cash and cash equivalents by $7.1 million from December 31, 2008.

Repriced derivatives during the second quarter of 2009 and received $26 million.

Historical Cash Flows and Liquidity

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

Cash flows from operations totaled $74.6 million for the year ended December 31, 2009, as compared to $61.9 million and $28.8 million for the years ended December 31, 2008 and 2007, respectively. The increase from 2008 to 2009 is attributable primarily to an increase in realized gains on our derivatives offset by lower revenues due to depressed oil and natural gas prices in 2009. The increase from 2007 to 2008 is attributable primarily to net cash from increased production and from higher average oil and natural gas prices in 2008 (although 2008 prices began to decline significantly in the third quarter of 2008) compared with average prices during 2007.

Cash Flows from Investing Activities. Cash flows from investing activities have historically been driven by sales of oil and gas properties, leasehold acquisitions, exploration and development, pipeline expansion and acquisitions of businesses. Net cash from investing activities totaled $0.3 million for the year ended December 31, 2009, as compared to cash used of $266.6 million and $272.5 million for the years ended December 31, 2008 and 2007, respectively. Cash from investing activities was minimal in 2009 compared to prior years as we had significantly pared down our acquisition and development related capital expenditures in response to liquidity constraints in 2009. Our liquidity constraints during 2009 were largely the result of required debt payments triggered by decreases in the borrowing base of QELP s credit facility, decreased revenues due to lower oil and natural gas market prices and increased general and administrative costs resulting from our internal investigation of the misappropriation, reaudits and restatements of previously issued financial statements and recombination activities. The following table sets forth our capital expenditures by major categories in 2009, 2008 and 2007.

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Capital expenditures:			
Leasehold acquisition	$ 1,998	$ 18,945	$ 15,847
Exploration	128	1,273	
Development	5,087	58,070	67,586
Acquisition of PetroEdge		142,618	
Acquisition of Seminole County, Oklahoma property		9,500	
Acquisition of KPC Pipeline			124,936
Pipelines	1,835	27,649	48,668
Other items (primarily capitalized overhead and interest)	511	9,061	7,832
Total capital expenditures	$ 9,559	$ 267,116	$ 264,869

Cash Flows from Financing Activities. Cash flows from financing activities have historically been driven by borrowing and repayments on debt instruments, issuances of common stock and the costs associated with these activities. Cash used in financing activities was $67.8 million for the year ended December 31, 2009, as compared to cash provided of $211.8 million and $216.5 million for the years ended December 31, 2008 and 2007, respectively. The cash used in financing activities in 2009 was primarily due to debt repayment of $67.4 million and $4.7 million in debt amendment fees offset by $4.3 million in proceeds from debt. In 2008, cash was provided by an increase in borrowings of $214.2 million and proceeds from issuance of common stock of $84.8 million, partially offset by repayments of note borrowings of $59.8 million, and $24.4 million of distributions to unitholders.

Working Capital Deficit. At December 31, 2009, we had current assets of $66.0 million. Our working capital (current assets minus current liabilities) was a deficit of $282.7 million at December 31, 2009 (excluding the short-term derivative asset and liability of $10.6 million and $1.4 million, respectively), compared to a working capital deficit of $41.5 million at December 31, 2008 (excluding the short-term derivative asset and liability of $43.0 million and $12,000 respectively). The decrease in our working capital was due to $310.0 million of our credit facilities being due in 2010. Of this amount, $282.5 million was due on July 11, 2010 because the recombination had not closed as of December 31, 2009. Subsequent to December 31, 2009, the recombination closed. Accordingly, the maturity date of the $282.5 million has been extended to March 31, 2011.

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Credit Agreements

QRCP

QRCP entered into a second amended and restated credit agreement with Royal Bank of Canada (RBC) on September 11, 2009. At the time of the amendment, QRCP s credit agreement included a term loan with principal balance of $28.3 million, an $8.0 million revolving line of credit and three promissory notes. The promissory notes included an $862,786 interest deferral note dated June 30, 2009 (representing outstanding due and unpaid interest on the term loan), a $282,500 payment-in-kind note dated May 29, 2009 (representing a 1% amendment fee payable by QRCP in connection with the fourth amendment to QRCP s credit facility), and a second $25,000 payment-in-kind note dated June 30, 2009 (representing an amendment fee payable by QRCP in connection with the fifth amendment to the credit facility). Interest on the term loan and promissory notes can be deferred at our election whereupon the deferred interest would be added to existing principal balances. On December 17, 2009, QRCP entered into a further amendment that provides for QRCP to guarantee the credit facilities of QELP and QMLP after the recombination and to pledge its ownership interests in QELP and QMLP to secure its guarantees. As of December 31, 2009, the balance, including deferred interest, of the term loan was $30.1 million and of the promissory notes was $1.3 million, while the balance on the revolving line of credit was $4.3 million.

Modification of Debt. As a result of the amendment and restatement to the credit agreement on September 11, 2009, QRCP evaluated the remaining cash flows of this facility under Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 470-50-40 *Debt Modifications and Extinguishments Derecognition* to determine if the facility had been substantially modified as defined by the guidance. Upon determining that a substantial modification had occurred, QRCP recorded an extinguishment of prior debt and the assumption of new debt at fair value. Our analysis indicated that the fair value of the new debt facility was not materially different from the principal amount of the previous debt facility. As a result, QRCP recorded a $0.8 million loss on extinguishment of debt which represents a write-off of unamortized debt issuance costs associated with the prior debt facility. The loss is reflected in interest expense in our consolidated statements of operations.

Interest Rate and Other Fees. Interest accrues on the QRCP term loan, the interest deferral note and the two payment-in-kind notes at the base rate plus 10.0%. The base rate varies daily and is generally the higher of the federal funds rate plus 0.50% or RBC s prime rate for such day. The revolving line of credit is non-interest bearing. QRCP is required to pay to the lenders a facility fee equal to $2.0 million on the earlier of July 11, 2010 and the date the facility fee reduction conditions described in the next sentence are satisfied. The facility fee will be proportionately reduced if all of the following facility fee reduction conditions are satisfied: (i) repayment and termination by QRCP of the revolving line of credit, (ii) payment of the deferred quarterly principal payments under the term loan as discussed below under Payments, (iii) repayment of the interest deferral note and the two payment-in-kind notes and (iv) payment of any deferred interest under the term loan, the interest deferral note and the two payment-in-kind notes as discussed below under Payments.

Additionally, two of QRCP s subsidiaries assigned to the lenders an overriding royalty interest in the oil and gas properties owned by them in the aggregate equal to 2% of its respective working interest (plus royalty interest, if any), proportionately reduced, in its respective oil and gas properties. Each lender agreed to reconvey the overriding royalty interest (and any accrued payments owing to such lender) if on or before July 11, 2010 the facility fee reduction conditions discussed above are satisfied and the term loan (together with accrued and unpaid interest) is paid in full. Each lender also agreed to reconvey the overriding royalty interest (but not any accrued payments owing to such lender) if on or before July 11, 2010 the facility fee reduction conditions discussed above are satisfied.

Payments. Quarterly principal payments of $1.5 million on the term loan due September 30, 2009, December 31, 2009, March 31, 2010 and June 30, 2010 have been effectively deferred until July 11, 2010, at which time all

$6 million will be due in order to satisfy the facility fee reduction conditions discussed above under Interest Rate and Other Fees. Commencing with the calendar quarter ended September 30, 2010,

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QRCP is required to make a principal repayment of $1.5 million at the end of each calendar quarter until maturity.

Maturity Dates. The maturity date of the term loan is January 11, 2012. The maturity date of the revolving line of credit, the interest deferral note and the two payment-in-kind notes is July 11, 2010. The revolving line of credit, term loan, interest deferral note and the two payment-in-kind notes may be prepaid at any time without any premium or penalty. On July 11, 2010, the total amount due by QRCP under its credit agreement (assuming the facility fee reduction conditions are all satisfied on that date) will be approximately $21 million.

Security Interest. The QRCP credit agreement is secured by a first priority lien on the oil and gas properties owned by Quest Eastern in the Appalachian Basin, which are substantially all of QRCP s assets. The assets of QMLP, QELP and their subsidiaries are not pledged to secure the QRCP term loan. The QRCP credit agreement provides that all obligations arising under the loan documents, including obligations under any hedging agreement entered into with lenders or their affiliates (or BP Corporation North America, Inc. or its affiliates), are secured *pari passu* by the liens granted under the loan documents. In connection with the recombination, the security interest in QRCP s ownership interest in QELP and QMLP was released in order to permit QRCP to pledge such ownership interests to secure its guarantee of the credit facilities of QELP and QMLP, respectively.

Covenants. The QRCP credit agreement contains non-financial affirmative and negative covenants that are customary for credit agreements of this type. The financial covenants have been removed from the QRCP credit agreement, but QRCP and RBC agreed that if the facility fee reduction conditions discussed above under Interest Rate and Other Fees are satisfied on or before July 11, 2010, they would negotiate in good faith to amend the credit agreement to add financial covenants customary for similar credit agreements of this type.

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 for a period of 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, and change of control. In addition, it was an event of default under QRCP s credit agreement if by January 15, 2010, QRCP had not (i) delivered to RBC evidence that the recombination has been agreed to by the lenders under QELP s and QMLP s credit agreements and (ii) delivered to RBC evidence that the board of directors of each of QRCP, QELP, QMLP and certain of their subsidiaries have approved the terms of any amendments, restatements or new credit facilities to renew, rearrange or replace the existing credit agreements of each of QELP and QMLP. This requirement was satisfied with the execution of the amendments to QELP s and QMLP s credit agreements on December 17, 2009.

QELP

Quest Cherokee Credit Agreement. QELP is a party, as a guarantor, to an amended and restated credit agreement with its wholly-owned subsidiary, Quest Cherokee, LLC (Quest Cherokee), as the borrower, RBC, as administrative agent and collateral agent, KeyBank National Association, as documentation agent and the lenders party thereto. QELP entered into a fifth amendment to the Quest Cherokee credit agreement on December 17, 2009. QELP agreed to pay an amendment fee of 0.50% of the outstanding principal amount of the Quest Cherokee credit agreement, which fee is payable on the maturity date of the loan. The outstanding balance under the credit agreement was $145 million as of December 31, 2009, with no available capacity.

Modification of Debt. As a result of the amendment to the credit agreement on December 17, 2009, QELP evaluated the change in borrowing capacity of this facility under FASB ASC 470-50-40 *Debt Modifications and Extinguishments Derecognition.* Upon determining that a reduction in borrowing capacity had occurred, QELP wrote off a pro-rata portion of prior unamortized debt issuance costs in the amount of $0.8 million while capitalizing

$3.4 million of direct costs associated with the current amendment. Included in this amount was $0.7 million that QELP, under the terms of the amendment, elected to defer payment until

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maturity of the credit agreement. The write-off is reflected in interest expense in the consolidated statements of operations.

Borrowing Base. The Quest Cherokee credit agreement consists of a three-year $145 million credit facility. In connection with the December 17, 2009 amendment, the revolving credit facility was converted to a term loan and no future borrowings are permitted under the credit facility. The maximum outstanding amount under the credit facility is tied to a borrowing base that will be redetermined by the lenders every three months taking into account the value of QELP s proved reserves. In addition, QELP and the required lenders each 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, and in certain other limited circumstances. If the borrowing base is reduced in connection with a redetermination, outstanding borrowings in excess of the new borrowing base will be required to be repaid (1) either within 30 days following receipt of notice of the new borrowing base or in two equal monthly installments beginning on or before the 30th day following receipt of notice of the new borrowing base or (2) immediately if the borrowing base is reduced in connection with a sale or disposition of certain properties in excess of 2% of the borrowing base. As of June 30, 2009, the borrowing base was $160 million (reduced from $190 million at December 31, 2008). At that time, there was a borrowing base deficiency which has been resolved but which left no remaining borrowing capacity. Effective December 17, 2009, QELP s borrowing base under its revolving credit agreement was further reduced to $145 million in connection with another borrowing base redetermination, which resulted in a borrowing base deficiency of $15 million. QELP repaid the borrowing base deficiency on December 17, 2009 in connection with the execution of the amendment to the Quest Cherokee credit agreement.

Payments. The outstanding principal amount of the Quest Cherokee credit agreement must be reduced to the amounts and by the dates specified below (in thousands):

March 31, 2010	$ 141,000
June 30, 2010	$ 141,000
September 30, 2010	$ 138,000
December 31, 2010	$ 134,000

The remaining balance of the Quest Cherokee credit agreement is due on the maturity date.

In addition, Quest Cherokee must make a prepayment within 20 business days after the end of each calendar quarter (beginning with the quarter ending March 31, 2010) in an amount equal to QELP s Excess Book Cash. Excess Book Cash is equal to book cash at the end of a quarter less the sum of the following: (i) restricted cash set aside for accrued royalty payments, (ii) restricted cash set aside to secure letters of credit, (iii) restricted cash set aside for accrued and unpaid taxes, (iv) quarterly estimated federal income taxes, to the extent not already reflected in (iii) above, (v) restricted cash set aside for any other amounts accrued and unpaid during the quarter and approved by the required lenders under the credit agreement, and (vi) $5 million.

Interest Rate. Interest generally accrues at either LIBOR plus 4.0% or the base rate plus 3.0%. The base rate varies daily and is generally the higher of the federal funds rate plus 0.50%, RBC s prime rate or LIBOR plus 1.25%.

Maturity Date. As of December 31, 2009, the maturity date of the Quest Cherokee credit agreement was July 11, 2010 since the recombination had not closed on that date. Subsequent to December 31, 2009, the recombination closed. Accordingly, the maturity date is March 31, 2011.

Security Interest. The Quest Cherokee credit agreement is secured by a first priority lien on substantially all of the assets of QELP and its subsidiaries. All obligations arising under the loan documents, including obligations under any hedging agreement entered into with the lenders and their affiliates (or BP Corporation North America, Inc. or its affiliates), are secured *pari passu* by the liens granted under the loan documents. The Quest Cherokee credit agreement is also secured by the guarantee of PostRock and QRCP and a pledge of all of QRCP s equity interest in QELP.

Covenants. The agreement contains affirmative and negative covenants that are customary for transactions of this type, including financial covenants that prohibit QELP, Quest Cherokee and any of their subsidiaries from:

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

- permitting the interest coverage ratio of adjusted consolidated EBITDA to consolidated interest charges at any fiscal quarter-end to be less than 2.5 to 1.0 measured on a rolling four quarter basis; and

- permitting the leverage ratio of consolidated funded debt to adjusted consolidated EBITDA at any fiscal quarter-end to be greater than 3.5 to 1.0 measured on a rolling four quarter basis.

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 for a period of 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, borrowing base deficiencies, and change of control.

The fifth amendment to the Quest Cherokee credit agreement excluded any actions to effect the recombination and the recombination itself from the definition of a change of control. The fifth amendment also added the concept of a change of control of PostRock as an event of default.

Second Lien Loan Agreement. QELP and Quest Cherokee are parties to a $45 million second lien loan agreement. QELP entered into an eighth amendment to the second lien loan agreement on December 17, 2009. QELP agreed to pay an amendment fee of 2.10% of the outstanding principal amount of the second lien loan agreement, which fee is payable on the maturity date of the loan. The fee will be partially forgiven if the second lien term loan is repaid in full on or before February 28, 2011. The outstanding balance under the loan was $29.8 million as of December 31, 2009.

Modification of Debt. As a result of the eighth amendment to the second lien loan on December 17, 2009, QELP evaluated the remaining cash flows of this facility under Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 470-50-40 *Debt Modifications and Extinguishments Derecognition* and determined that facility had not been substantially modified. An additional $0.9 million of direct costs associated with the amendment was capitalized. Included in this amount was $0.6 million that QELP, under the terms of the amendment, elected to defer payment until maturity of the loan.

Interest Rate. Interest accrues under the second lien loan agreement at either LIBOR plus 11.0% (with a LIBOR floor of 3.5%) or the base rate plus 10.0%. The base rate varies daily and is generally the higher of the federal funds rate plus 0.5%, RBC s prime rate or LIBOR plus 1.25%. Amounts due under the second lien loan agreement may be prepaid without any premium or penalty, at any time. QELP may elect to defer the payment of a portion of the interest (at the rate of up to 2%) until maturity. If any amount is outstanding under the Quest Cherokee credit agreement, such interest amount must be deferred. Deferred interest will bear interest.

Payments. No prepayments may be made on the second lien term loan while the Quest Cherokee credit agreement is outstanding. After the Quest Cherokee credit agreement is paid in full, Quest Cherokee must make a prepayment within 20 business days after the end of each calendar quarter (beginning with the quarter ending March 31, 2010) in an amount equal to QELP s Excess Book Cash.

Maturity Date. As of December 31, 2009, the maturity date of the second lien loan agreement was July 11, 2010 since the recombination had not closed on that date. Subsequent to December 31, 2009, the recombination closed. Accordingly, the maturity date is March 31, 2011.

Security Interest. The second lien loan agreement is secured by a second priority lien on substantially all of the assets of QELP and its subsidiaries. The second lien loan agreement is also secured by the guarantee of PostRock and QRCP (which is subordinated to the guarantees of the Quest Cherokee credit agreement and the QMLP credit agreement) and a second lien pledge of all of QRCP s equity interest in QELP.

Covenants. The second lien loan agreement contains affirmative and negative covenants that are customary for credit agreements of these types, including financial covenants that prohibit QELP, Quest Cherokee and any of their subsidiaries from:

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

permitting the interest coverage ratio of adjusted consolidated EBITDA to consolidated interest charges at any fiscal quarter-end to be less than 2.5 to 1.0 measured on a rolling four quarter basis; and

permitting the leverage ratio of consolidated funded debt to adjusted consolidated EBITDA at any fiscal quarter-end to be greater than 3.5 to 1.0 measured on a rolling four quarter basis.

The second lien loan agreement contains an additional financial covenant that prohibits QELP, Quest Cherokee, and any of their subsidiaries from permitting the total reserve leverage ratio (ratio of total proved reserves to consolidated funded debt) at any fiscal quarter-end to be less than 1.5 to 1.0.

Events of Default. Events of default under the second lien loan agreement 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 for a period of 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 and change of control.

The eighth amendment to the Quest Cherokee credit agreement excluded any actions to effect the recombination and the recombination itself from the definition of a change of control. The eighth amendment also added the concept of a change of control of PostRock as an event of default.

QMLP

QMLP and Bluestem Pipeline, LLC, as borrowers, entered into a third amendment to the amended and restated QMLP credit agreement on December 17, 2009. The borrowers agreed to pay an amendment fee of 0.50% of the outstanding principal amount of the QMLP credit agreement, which fee is payable on the maturity date of the loan. In connection with the December 17, 2009 amendment, the QMLP credit agreement was converted to a term loan and no future borrowings are permitted under the QMLP credit agreement. As of December 31, 2009, the outstanding principal amount of the QMLP credit agreement was $118.7 million with $1.0 million of capacity available only for letters of credit.

Modification of Debt. As a result of the amendment to the credit agreement on December 17, 2009, QMLP evaluated the change in borrowing capacity of this facility under FASB ASC 470-50-40 *Debt Modifications and Extinguishments Derecognition.* Upon determining that a reduction in borrowing capacity had occurred, QMLP wrote off a pro-rata portion of prior unamortized debt issuance costs in the amount of $1.9 million while capitalizing $2.1 million of direct costs associated with the amendment. Included in this amount was $0.6 million that QMLP, under the terms of the amendment, elected to defer payment until maturity of the credit agreement. The write-off is reflected in interest expense in the consolidated statements of operations.

Interest Rate. Interest accrues at either LIBOR plus a margin ranging from 2.0% to 3.5% (depending on the total leverage ratio) or the base rate plus a margin ranging from 1.0% to 2.5% (depending on the total leverage ratio), at the borrowers option. The base rate is generally the higher of the federal funds rate plus 0.5%, RBC s prime rate or LIBOR plus 1.25%.

Payments. There are no scheduled principal payments prior to the maturity date.

Maturity Dates. As of December 31, 2009, the maturity date of the QMLP credit agreement was July 11, 2010 since the recombination had not been closed on that date. Subsequent to December 31, 2009, the recombination closed. Accordingly, the maturity date is March 31, 2011.

Security Interest. The QMLP credit agreement is secured by a first priority lien on substantially all of the assets of QMLP and its subsidiaries. The QMLP credit agreement is also secured by the guarantee of PostRock and QRCP and a pledge of all of QRCP s equity interest in QMLP.

Covenants. The QMLP credit agreement contains affirmative and negative covenants that are customary for credit agreements of this type.

The QMLP credit agreement contains financial covenants that prohibit QMLP and any of its subsidiaries from:

permitting the interest coverage ratio (ratio of adjusted consolidated EBITDA to consolidated interest charges) on a rolling four quarter basis to be less than 2.50 to 1.00 for the fiscal quarter ending on or prior to March 31, 2010 and increasing to 2.75 to 1.00 for each fiscal quarter end thereafter; and

permitting the total leverage ratio (ratio of adjusted consolidated funded debt to adjusted consolidated EBITDA) on a rolling four quarter basis to be greater than 5.00 to 1.00 for the fiscal quarter ending on or prior to March 31, 2010, and decreasing to 4.50 to 1.00 for each fiscal quarter end thereafter.

Events of Default. Events of default under the QMLP credit agreement 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 for a period of 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, and change of control.

The third amendment to the QMLP Credit Agreement excluded any actions to effect the recombination and the recombination itself from the definition of a change of control. The third amendment also added the concept of a change of control of PostRock as an event of default.

As a result of the recent expiration of MGE s firm transportation contract with the KPC Pipeline and the expected decrease in 2010 in the gathering and compression fees charged under the midstream services agreement between QELP and a subsidiary of QMLP as a result of the low natural gas prices in 2009, QMLP may not be in compliance with the total leverage ratio covenant commencing with the second quarter of 2010, if it is not able to reduce its expected total indebtedness as of June 30, 2010 and/or increase its anticipated EBITDA for the quarter ended June 30, 2010. If QMLP were to default, the lenders could accelerate the entire amount due under the QMLP credit agreement.

Sources of Liquidity in 2010 and Capital Requirements

During 2009, due to lower gas prices and the amount of the gathering rate QELP was obligated to pay to QMLP relative to the price at which it could sell its gas, it was not economical for QELP to drill new wells, complete existing wells or produce gas from new wells. Furthermore, QRCP did not have the capital necessary to drill any wells. Therefore, the only wells drilled and completed in 2009 were the seven necessary to hold otherwise expiring acreage. If we can successfully refinance our debt, we will be able to operate as one entity and the gathering costs are an expense of production without a built-in profit, allowing us to be in a better position to drill, complete and profitably produce gas, even in a low gas price environment. In addition, management believes that the recombination has put us in a better position to add reserves and production, depending on capital availability. Management also expects the recombined production and gathering operations and the simplified structure of the organization to be more attractive to potential capital providers.

In 2010, we intend to focus on maintaining a stable asset base, improving the profitability of our assets by increasing our utilization while controlling costs and raising equity capital. For 2010, we have budgeted approximately $6.0 million to complete and $5.5 million to connect 108 gross wells that were previously drilled but not completed, $2.7 million for land and equipment in the Cherokee Basin, $20 million of net

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expenditures to drill and complete three vertical wells and six horizontal wells and $2.5 million for land, equipment and connections in the Appalachian Basin. These wells will be drilled on locations that are classified as containing proved reserves in the December 31, 2009 reserve report. We intend to fund these capital expenditures only to the extent that we have available cash from operations after taking into account our debt service and other obligations, and with the proceeds from additional equity capital issuances and borrowings.

In order to accomplish the goals and objectives set forth above, no later than the first half of 2010, we will need to either refinance our debt to allow for available capital or raise a sufficient amount of equity capital to fund our drilling program and pay down outstanding indebtedness. We may not be able to raise a sufficient amount of equity capital for these purposes at the appropriate time which would restrict our ability to fund our operations and capital expenditures and we may be forced to file for bankruptcy. We are actively seeking to refinance our current credit facilities, although we may not be able to do so on favorable terms or at all.

As discussed above, quarterly principal payments of $1.5 million on QRCP s term loan due September 30, 2009, December 31, 2009, March 31, 2010 and June 30, 2010 are deferred until July 11, 2010, at which time all $6 million will be due. In addition, the maturity date of the revolving line of credit, interest deferral notes and the two payment-in-kind notes will be July 11, 2010. On July 11, 2010, the total amount due by QRCP under its credit agreement (assuming the facility fee reduction conditions are all satisfied on that date) would be approximately $21 million. Payments of principal under the Quest Cherokee credit agreement in the amounts of $4.0 million, $0, $3.0 million and $4.0 million are due on the last day of each quarter of 2010. In addition, QELP may be required to make additional prepayments at the end of each calendar quarter beginning with the quarter ending March 31, 2010. There is no assurance that we will have sufficient funds to pay these amounts when they come due.

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, 2009 after giving effect to the extension of the maturity date of various facilities that occurred upon closing of the recombination:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
	(In thousands)				
Revolving Credit Facility QRCP	$ 4,300	$ 4,300	$	$	$
Term Loan and Promissory Notes QRCP	31,358	12,108	19,250		
1st Lien Term Loan QELP	145,000	11,000	134,000		
2nd Lien Loan QELP	29,821		29,821		
Term Loan QMLP	118,728		118,728		
Other Note obligations	103	58	34	11	
Interest expense on bank credit facilities	26,055	20,461	5,594		
Operating lease obligations	17,141	8,929	4,369	2,060	1,783
Total commitments	$ 372,506	$ 56,856	$ 311,796	$ 2,071	$ 1,783

Off-Balance Sheet Arrangements

At December 31, 2009, 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.

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 the 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.

In December 2008, the SEC adopted the final rules for the Modernization of Oil and Gas Reporting. The new rules require reporting of oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices and permit the use of new technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies also are allowed to disclose probable and possible reserves in SEC filed documents. In addition, companies are required to report the independence and qualifications of its reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit and potentially modify the classifications of proved and producing reserves. The calculation of reserves using an average price is a significant change that should reduce the volatility of our reserve calculation and could impact any potential future impairments arising from our ceiling test.

Oil and Gas Properties

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

Oil and gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved oil and gas reserves. Estimation of proved oil and gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Holding all other factors constant, if proved oil and gas reserves were revised upward or downward, earnings would increase or decrease, respectively. Subsequent proved reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition represents a significant quantity of reserves, which 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 gas properties increases when gas prices are depressed, even if low prices are temporary. In addition, a write-down may occur if estimates of proved reserves are substantially reduced or estimates of future development costs increase significantly.

Through the quarter ended September 30, 2009, the ceiling test was calculated using natural gas prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. Beginning with the quarter ended December 31, 2009, a twelve-month average price is used and adjusted for basis differentials. In addition, subsequent to the adoption of FASB ASC 400-20 *Retirement and Environmental Obligations-Asset Retirement Obligation*, the future cash outflows associated with settling asset retirement obligations are not included in the computation of the discounted present value of future net revenues for the purpose of the ceiling test calculation.

Unevaluated Properties

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

Future Abandonment Costs

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

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

We have not recorded any asset retirement obligations relating to our gathering systems as of December 31, 2009 and 2008 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 natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of prices we receive for our production. Currently, we use collars, fixed-price swaps and fixed price sales contracts as our mechanism for hedging commodity prices. Our current derivative instruments are not accounted for as hedges for accounting purposes in accordance with FASB ASC 815 *Derivatives and Hedging* (FASB ASC 815). As a result, we account for our derivative instruments on a mark-to-market basis, and changes in the fair value of derivative instruments are recognized as gains and losses which are included in other income and expense in the period of change. While we believe that the stabilization of prices and production afforded us by providing a revenue floor for our production is beneficial, this strategy may result in lower revenues than we would have if we were not a party to derivative instruments in times of rising natural gas prices. As a result of rising commodity prices, we may recognize additional charges to future periods; however, for the year ended December 31, 2009, we recognized a total gain on derivative financial instruments in the amount of $48.1 million, consisting of a $98.1 million realized gain and a $50.0 million unrealized loss. Our estimates of fair value are determined by the use of an option-pricing model that is based on various assumptions and factors including the time value of options, volatility, and closing NYMEX market indices.

Revenue Recognition

We derive revenue from our oil and natural gas operations from the sale of produced oil and natural gas. We use the sales method of accounting for the recognition of oil and gas revenue. Because there is a ready market for oil and natural gas, we sell our oil and natural 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 our net revenue interests. Oil and gas sold in production operations is not significantly different from our share of production based on our interest in the properties.

Settlement of oil and gas sales occur after the month in which the oil and gas was produced. We estimate and accrue for the value of these sales using information available at the time the financial statements are generated. Differences are reflected in the accounting period that payments are received from the purchaser.

Revenue from our pipeline operations is recognized at the time the natural gas is gathered or transported through the system and delivered to a third party.

Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of FASB ASC 740 *Income Taxes* (FASB ASC 740). 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.

Estimating the amount of valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that could trigger limits on use of net

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operating losses under Internal Revenue Code section 382. We have a significant deferred tax asset associated with net operating loss carry-forward (NOLs).

Recent Accounting Pronouncements

In June 2009, the FASB issued FASB ASC 105 *Generally Accepted Accounting Principles* (FASB ASC 105), which establishes FASB ASC as the sole source of authoritative GAAP. Pursuant to the provisions of FASB ASC 105, we have updated references to GAAP in our financial statements for the year ended December 31, 2009. The adoption of this standard did not have a material impact on our consolidated financial statements.

In March 2008, the FASB issued provisions under FASB ASC 815 that did not change the accounting for derivatives but does require enhanced disclosures about derivative strategies and accounting practices. We adopted these provisions effective January 1, 2009.

We adopted the provisions of FASB ASC 260 *Earnings Per Share* (FASB ASC 260), effective January 1, 2009, with respect to whether instruments granted in share-based payment transactions are considered participating securities prior to vesting and therefore included in the allocation of earnings for purposes of calculating earnings per share (EPS) under the two-class method as required by FASB ASC 260. FASB ASC 260 provides that unvested unit-based awards that contain non-forfeitable rights to dividends are participating securities and should be included in the computation of EPS. Our restricted stock units contain non-forfeitable rights to dividends and thus require these awards to be included in the EPS computation. All prior periods have been conformed to the current year presentation. During periods of losses, EPS will not be impacted, as our participating securities are not obligated to share in our losses and thus, are not included in the EPS share computation.

In December 2008, the SEC issued Release No. 33-8995, *Modernization of Oil and Gas Reporting*, which revises disclosure requirements for oil and gas companies. In addition to changing the definition and disclosure requirements for oil and gas reserves, the new rules change the requirements for determining oil and gas reserve quantities. These rules permit the use of new technologies to determine proved reserves under certain criteria and allow companies to disclose their probable and possible reserves. The new rules also require companies to report the independence and qualifications of their reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit. The new rules also require that oil and gas reserves be reported and the full cost ceiling limitation be calculated using a twelve-month average price rather than period-end prices. We implemented new rules at December 31, 2009. The impact of this change in prices was to increase depletion expense by approximately $1.0 million for the fourth quarter of 2009.

In May 2009, the FASB issued FASB ASC 855 *Subsequent Events* (FASB ASC 855). FASB ASC 855 establishes general standards of accounting for and disclosure of transactions and events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It also requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. We adopted FASB ASC 855 beginning with the period ended June 30, 2009.

In December 2007, the FASB issued FASB ASC 810 *Consolidation* (FASB ASC 810). FASB ASC 810 establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the non-controlling interest, and changes in a parent s ownership interest while the parent retains its controlling financial interest in its subsidiary. In addition, FASB ASC 810 establishes principles for valuation of retained non-controlling equity investments and measurement of gain or loss when a subsidiary is deconsolidated. FASB ASC 810-10 also establishes disclosure requirements to clearly identify and distinguish between interests of the parent and the interests of the non-controlling owners. We adopted FASB ASC 810 effective January 1, 2009. Under FASB ASC 810, QRCP is required to classify amounts previously presented as a minority interest liability as a component of equity in the condensed consolidated balance sheet and is required to present net income (loss) attributable to QRCP and the noncontrolling partners ownership interest separately in the condensed consolidated statement of operations. All prior periods have been reclassified to comply with FASB ASC 810.

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

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 $81.37 per barrel in October 2009 to $33.98 per barrel in February 2009, with an average of approximately $62.09 per barrel in 2009. Meanwhile, near month NYMEX natural gas futures prices ranged from a high of $6.07 per Mmbtu in January 2009 to a low of $2.51 per Mmbtu in September 2009, with an average of approximately $4.16 per Mmbtu in 2009. 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 oil and natural gas prices we receive for our production. From time to time, we enter into commodity pricing derivative contracts for a portion of our anticipated production volumes to provide certainty on future sales prices and reduce revenue volatility.

We use, 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 natural gas derivative contracts typically occurs in advance of our purchaser receipts.

While we believe that the oil and natural 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 oil and natural gas prices. We establish fair value of our derivative contracts by price quotations obtained from counterparties to the derivative contracts. 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 commodities derivative contracts. Changes in fair value are principally measured based on period-end 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 ended December 31, 2009, 2008 and 2007 (in thousands):

	2009	2008	2007
Realized gain (loss)	$ 98,148	$ (6,388)	$ 7,279
Unrealized gain (loss)	(50,026)	72,533	(5,318)
Total gain from derivative financial instruments	$ 48,122	$ 66,145	$ 1,961

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The following table summarizes the estimated volumes, fixed prices and fair value attributable to oil and gas derivative contracts as of December 31, 2009:

	Year Ending December 31,									
	2010		2011		2012		2013		Total	
	($ in thousands, except volumes and per unit data)									
Natural Gas Swaps:										
Contract volumes (Mmbtu)		16,129,060		13,550,302		11,000,004		9,000,003		49,679,369
Weighted-average fixed price per Mmbtu	$	6.26	$	6.80	$	7.13	$	7.28	$	6.78
Fair value, net	$	10,424	$	7,530	$	6,662	$	4,763	$	29,379
Natural Gas Basis Swaps:										
Contract volumes (Mmbtu):		3,630,000		8,549,998		9,000,000		9,000,003		30,180,001
Weighted-average fixed price per Mmbtu	$	(0.63)	$	(0.67)	$	(0.70)	$	(0.71)	$	(0.69)
Fair value, net	$	(1,402)	$	(2,973)	$	(2,879)	$	(2,717)	$	(9,971)
Crude Oil Swaps:										
Contract volumes (Bbl)		30,000								30,000
Weighted-average fixed price per Bbl	$	87.50	$		$		$		$	87.50
Fair value, net	$	155	$		$		$		$	155
Total fair value, net	**$**	**9,177**	**$**	**4,557**	**$**	**3,783**	**$**	**2,046**	**$**	**19,563**

Interest Rate Risk

Although none are currently outstanding, in the past, we have entered into interest rate derivatives to mitigate our exposure to fluctuations in interest rates on variable rate debt. These instruments have not been designated as hedges and, therefore, are recorded in the consolidated balance sheet at fair value with changes in fair value recognized in earnings as they occur.

As of December 31, 2009, we had outstanding $324.9 million of variable-rate debt. A 1% increase in our interest rates would increase gross interest expense approximately $3.2 million per year.

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

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

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

None.

ITEM 9A(T). ***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, 2009. While significant improvements have been implemented, we identified material weaknesses in our internal control over financial reporting, as discussed below, primarily due to the inability to sufficiently test newly implemented controls. As a result, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were not effective as of December 31, 2009. Notwithstanding this determination, our management believes that the consolidated financial statements in this Annual Report on Form 10-K fairly present, in all material respects, our financial position and results of operations and cash flows as of the dates and for the periods presented, in conformity with GAAP.

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 (COSO).

Based on the evaluation performed, we identified the following material weaknesses in our internal control over financial reporting as of December 31, 2009. A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

(1) *Control environment* We did not maintain a sufficient control environment. The control environment, which is the responsibility of senior management, sets the tone of the organization, influences the control consciousness of its people, and is the foundation for all other components of internal control over financial reporting. Specifically, during the first two quarters of 2009, management s attention was focused on the restatement and reaudit of prior year financial statements and the recombination, which resulted in the full implementation of our remediation plan being

delayed until the third quarter of 2009. During the first two quarters of 2009, only specific identified risks related to items such as the fraud hotline, segregation of duties and cash management controls were actively monitored.

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(2) *Internal control over financial reporting* We did not maintain sufficient monitoring controls to determine the adequacy of our internal control over financial reporting. Specifically, we did not design and implement policies and procedures necessary to sufficiently determine and monitor the adequacy of our internal control over financial reporting.

These material weaknesses relating to the overall control environment and monitoring of our internal control over financial reporting contributed to the material weaknesses described in items (3) through (6) below.

(3) *Period-end financial close and reporting* We did not maintain sufficient controls over certain of our period-end financial close and reporting processes. Specifically, we did not maintain controls over the preparation and review of the interim and annual consolidated financial statements to sufficiently ensure that we identified and accumulated all required supporting information to support the completeness and accuracy of the consolidated financial statements and that balances and disclosures reported in the consolidated financial statements reconciled to the underlying supporting schedules and accounting records.

(4) *Stock compensation cost* We did not maintain sufficient controls to ensure completeness and accuracy of stock compensation costs. Specifically, controls did not operate sufficiently throughout the period to ensure that all stock transactions were properly communicated in order to be recorded accurately.

(5) *Depreciation, depletion and amortization* We did not maintain sufficient controls to ensure completeness and accuracy of depreciation, depletion and amortization expense. Specifically, controls did not operate sufficiently to appropriately calculate and review the depletion of oil and gas properties.

(6) *Impairment of oil and gas properties* We did not maintain sufficient controls to ensure the accuracy and application of GAAP related to the impairment of oil and gas properties and, specifically, to determine, review and record oil and gas property impairments.

Each of the control deficiencies described in items (1) through (6) above could result in a misstatement of the aforementioned account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

Based on the material weaknesses described above, management has concluded that our internal control over financial reporting was not effective as of December 31, 2009 based on criteria set forth in the COSO framework.

Changes in Internal Control Over Financial Reporting

During 2009, we implemented certain measures to improve our internal control over financial reporting and to remediate previously identified material weaknesses:

(a) Appointed a new management team which, under the direction of the Board of Directors, was tasked with achieving and maintaining a strong control environment, high ethical standards, and financial reporting integrity. In January 2009, Mr. Eddie LeBlanc was appointed Chief Financial Officer (our principal financial and accounting officer), and in May 2009, Mr. David Lawler was appointed Chief Executive Officer (our principal executive officer);

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

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

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

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

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

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

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

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

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

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

We believe these measures have strengthened our internal control over financial reporting and disclosure controls and procedures and have effectively remediated our remaining control deficiencies for future reporting periods. We are unable to conclude that the material weaknesses identified above have been remediated, however, because the measures we have implemented have not been fully tested.

Our new leadership team, together with other senior executives and our Board of Directors, is committed to achieving and maintaining a strong control environment, high ethical standards, and financial reporting integrity. This commitment has been and will continue to be communicated to and reinforced with our employees and to external stakeholders.

In addition, under the direction of the Board of Directors, management will continue to review and make changes to the overall design of our internal control environment, as well as policies and procedures to improve the overall effectiveness of internal control over financial reporting and our disclosure controls and procedures.

Except for the remediation efforts discussed above, there was no change in our internal control over financial reporting that occurred during the fourth quarter of 2009 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 which is not required to be included until the 2010 Annual Report is filed, pursuant to the final implementation extension of Item 308T (a)(4) of Regulation S-K, granted by the SEC.

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

None.

PART III

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

Information required by Part III, Item 10 will be filed as an amendment to this Form 10-K no later than 120 days after the end of the registrant s fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended.

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

Information required by Part III, Item 11 will be filed as an amendment to this Form 10-K no later than 120 days after the end of the registrant s fiscal year, to the extent required by 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 will be filed as an amendment to this Form 10-K no later than 120 days after the end of the registrant s fiscal year, to the extent required by 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 will be filed as an amendment to this Form 10-K no later than 120 days after the end of the registrant s fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended.

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

Information required by Part III, Item 14 will be filed as an amendment to this Form 10-K no later than 120 days after the end of the registrant s fiscal year, to the extent required by the Securities and Exchange Act of 1934, as amended.

PART IV

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

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

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

Index to Financial Statements

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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 balance sheet of PostRock Energy Corporation (the Company) as of December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement is 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 financial statement. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet referred to above presents fairly, in all material respects, the financial position of PostRock Energy Corporation as of December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP
Houston, Texas
February 22, 2010
(Except for Note 3, as to which the date is March 17, 2010)

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POSTROCK ENERGY CORPORATION

BALANCE SHEET

	December 31, 2009
ASSETS	
Current assets:	
Cash and cash equivalents	$ 10
Total assets	$ 10
LIABILITIES AND STOCKHOLDER S EQUITY	
Stockholder s equity:	
Common stock, $0.01 par value; authorized shares 1,000; issued and outstanding 1,000	$ 10
Total liabilities and stockholder s equity	$ 10

The accompanying notes are an integral part of these financial statements

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Note 1 Organization and Nature of Operations

PostRock Energy Corporation is a Delaware corporation formed on July 1, 2009 under the name New Quest Holdings Corp. for the purpose of effecting the recombination of Quest Resource Corporation (QRCP), Quest Energy Partners, L.P. (QELP) and Quest Midstream Partners, L.P. (QMLP). On October 2, 2009, the corporation changed its name to PostRock Energy Corporation. As of December 31, 2009, PostRock has not conducted any business operations other than incidental to its formation and in connection with the transactions contemplated by the merger agreement pursuant to which the recombination was effected.

Note 2 Statements of Operations, Cash Flows and Equity

As discussed above, PostRock did not conduct any business operations for the period from inception on July 1, 2009 through December 31, 2009 other than incidental to its formation and in connection with the proposed recombination. As such, the statements of operations, cash flows and equity have been omitted.

Note 3 Subsequent Events

Recombination

On July 2, 2009, PostRock entered into a merger agreement (as amended, the merger agreement) with QRCP, QELP, QMLP, Quest Midstream GP, LLC (QMGP), Quest Energy GP, LLC (QEGP) and other parties thereto, pursuant to which QRCP, QELP and QMLP agreed to recombine as PostRock s wholly owned subsidiaries through a series of mergers and entity conversions (the recombination). The merger agreement was entered into as a result of a strategic review undertaken by QRCP, QELP and QMLP in response to liquidity challenges faced by those companies in 2009. The recombination closed on March 5, 2010. In connection with the closing of the recombination, the following transactions took place:

Quest Resource Acquisition Corp., a wholly owned subsidiary of PostRock, merged with and into QRCP and QRCP common stockholders received 0.0575 shares of PostRock common stock in exchange for each share of QRCP common stock held;

Quest Energy Acquisition, LLC, a wholly owned subsidiary of QRCP, merged with and into QELP (the QELP merger) and QELP common unitholders (other than QRCP) received 0.2859 shares of PostRock common stock in exchange for each QELP common unit held; and

QMLP merged with and into Quest Midstream Acquisition, LLC, a wholly owned subsidiary of QRCP (the QMLP merger), QMLP common unitholders received 0.4033 shares of PostRock common stock in exchange for each QMLP common unit held and the general partner interests in QMLP were converted into shares of PostRock common stock equal to approximately 0.14% of the PostRock common stock issued in the recombination.

Following the QELP merger, QELP, as a wholly owned subsidiary of QRCP, converted into a Delaware limited liability company. In the conversion, the general partner interests in QELP were cancelled for no consideration. QEGP then merged with and into that limited liability company. In addition, following the QMLP merger, QMGP merged with and into the surviving entity of the QMLP merger. In that merger, each holder of QMGP units other than QRCP received their pro rata portion of the shares of PostRock common stock receivable by QMGP in the QMLP merger described above.

Termination of Certain Intercompany Agreements

Pursuant to the merger agreement, each of the following intercompany agreements was terminated effective as of the closing of the recombination:

Omnibus Agreement among QRCP, QMGP, Bluestem Pipeline, LLC and QMLP, dated December 22, 2006;

Omnibus Agreement among QELP, QEGP and QRCP, dated November 15, 2007; and

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Amended and Restated Investors Rights Agreement, dated November 1, 2007, among QMLP, QMGP, QRCP and certain private investors of QMLP party thereto.

Registration Rights Agreement

PostRock has granted to certain QMLP unitholders registration rights under a registration rights agreement that was executed on the closing date of the recombination. The registration rights agreement requires PostRock to file a resale registration statement to register the shares of PostRock common stock that were received by such QMLP unitholders in the recombination if, at any time on or after the date that is 90 days after the closing date of the recombination, any such QMLP unitholders make a written request to PostRock for registration of their shares. Under the registration rights agreement, PostRock is required to use its commercially reasonable efforts to cause such resale registration statement to become effective within 210 days after its initial filing.

Other

We have evaluated our activity, through the issuance date, for recognized and unrecognized subsequent events not discussed elsewhere in these footnotes and determined there were none.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Quest Resource Corporation:

We have audited the accompanying consolidated balance sheets of Quest Resource Corporation and Subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, cash flows and stockholders (deficit) equity for each of the three years in the period ended December 31, 2009. These 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, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Quest Resource Corporation and Subsidiaries as of December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements for the year ended December 31, 2009, have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, the Company s recurring losses from operations, accumulated deficit, and inability to generate sufficient cash flow to meets its obligations and sustain its operations raise substantial doubt about its ability to continue as a going concern. Management s plans concerning these matters are also discussed in Note 1 to the consolidated financial statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 20 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements for the year ended December 31, 2009.

/s/ UHY LLP
Houston, Texas
February 22, 2010
(Except for Note 18, as to which the date is March 17, 2010)

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	($ in thousands, except share and per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,884	$ 13,785
Restricted cash	718	559
Accounts receivable trade, net	13,707	16,715
Other receivables	2,269	9,434
Inventory	9,702	11,420
Other current assets	8,141	2,858
Current derivative financial instrument assets	10,624	42,995
Total current assets	66,045	97,766
Oil and natural gas properties under full cost method of accounting, net	40,478	172,537
Pipeline assets, net	136,017	310,439
Other property and equipment, net	19,433	23,863
Other assets, net	2,727	14,735
Long-term derivative financial instrument assets	18,955	30,836
Total assets	$ 283,655	$ 650,176
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 10,852	$ 35,804
Revenue payable	5,895	8,309
Accrued expenses	11,417	7,138
Current portion of notes payable	310,015	45,013
Current derivative financial instrument liabilities	1,447	12
Total current liabilities	339,626	96,276
Non-current liabilities:		
Long-term derivative financial instrument liabilities	8,569	4,230
Notes payable	19,295	343,094
Other	6,552	5,922
Commitments and contingencies		
Stockholders equity:		
Preferred stock, $0.001 par value; authorized shares 50,000,000; none issued and outstanding		
Common stock, $0.001 par value; authorized shares 200,000,000; issued 32,160,121 and 32,224,643 at December 31, 2009 and 2008; outstanding 31,981,317 and	33	33

31,720,312 at December 31, 2009 and 2008, respectively		
Additional paid-in capital	299,010	298,583
Treasury stock at cost	(7)	(7)
Accumulated deficit	(447,413)	(302,491)
Total stockholders deficit	(148,377)	(3,882)
Noncontrolling interests	57,990	204,536
Total (deficit) equity	(90,387)	200,654
Total liabilities and equity	$ 283,655	$ 650,176

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

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2009	2008	2007
	($ in thousands, except share and per share data)		
Revenue:			
Oil and gas sales	$ 79,893	$ 162,499	$ 105,285
Gas pipeline revenue	26,188	28,176	9,853
Total revenues	106,081	190,675	115,138
Costs and expenses:			
Oil and gas production	33,451	44,111	36,295
Pipeline operating	29,083	29,742	21,098
General and administrative expenses	41,723	28,269	21,023
Depreciation, depletion and amortization	47,802	70,445	39,782
Impairments	268,630	298,861	
Loss (recovery) from misappropriation of funds	(3,412)		2,000
Total costs and expenses	417,277	471,428	120,198
Operating loss	(311,196)	(280,753)	(5,060)
Other income (expense):			
Gain from derivative financial instruments	48,122	66,145	1,961
Gain (loss) on sale of assets		24	(322)
Other income (expense)	83	305	(9)
Interest expense	(29,573)	(25,609)	(44,044)
Interest income	244	236	416
Total other income (expense)	18,876	41,101	(41,998)
Loss before income taxes and noncontrolling interests	(292,320)	(239,652)	(47,058)
Income tax benefit (expense)			
Net loss	(292,320)	(239,652)	(47,058)
Net loss attributable to noncontrolling interests	147,398	72,268	2,904
Net loss attributable to common shareholders	$ (144,922)	$ (167,384)	$ (44,154)
Net loss attributable to common stockholders per share:			
Basic and diluted	$ (4.55)	$ (6.20)	$ (1.97)
Weighted average common and common equivalent shares outstanding:			
Basic and diluted	31,833,222	27,010,690	22,379,479

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

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	2008	2007
	($ in thousands)		
Cash flows from operating activities:			
Net loss	$ (292,320)	$ (239,652)	$ (47,058)
Adjustments to reconcile net loss to cash provided by operations:			
Depreciation, depletion and amortization	47,802	70,445	39,782
Impairments	268,630	298,861	
Stock-based compensation	1,279	2,425	7,218
Amortization of deferred financing costs	7,761	2,100	11,220
Change in fair value of derivative financial instruments	50,026	(72,533)	5,318
Bad debt expense			22
Recovery of misappropriated funds, net of liabilities assumed	(977)		
Loss on disposal of property and equipment	25		1,363
Other non-cash changes to items affecting net loss	1,000		
Change in assets and liabilities:			
Accounts receivable	3,008	(1,158)	(5,928)
Other receivables	7,165	(7,954)	(1,245)
Other current assets	1,461	4,173	(2,827)
Other assets	193	318	15
Accounts payable	(25,115)	5,233	14,347
Revenue payable	(2,526)	584	2,736
Accrued expenses	7,142	(1,187)	4,001
Other long-term liabilities	65	404	220
Other		(159)	(388)
Net cash flows from operating activities	74,619	61,900	28,796
Cash flows from investing activities:			
Restricted cash	(159)	677	(86)
Acquisition of business PetroEdge		(141,777)	
Acquisition of business KPC			(133,725)
Equipment, development, leasehold and pipeline	(8,426)	(141,553)	(138,657)
Proceeds from sale of oil and gas properties	8,898	16,100	
Net cash flows from investing activities	313	(266,553)	(272,468)
Cash flows from financing activities:			
Proceeds from bank borrowings		86,195	44,580
Repayments of note borrowings	(14,141)	(59,800)	(225,441)
Proceeds from revolver note	4,300	128,000	224,000
Repayment of revolver note	(53,272)		(35,000)
Proceeds from Quest Energy			163,800

Proceeds from Quest Midstream			75,230
Syndication costs			(14,618)
Distributions to unitholders		(24,413)	(5,872)
Refinancing costs	(4,720)	(3,018)	(10,147)
Repurchase of restricted stock		(7)	
Proceeds from issuance of common stock		84,801	
Net cash flows from financing activities	(67,833)	211,758	216,532
Net increase (decrease) in cash	7,099	7,105	(27,140)
Cash and cash equivalents beginning of period	13,785	6,680	33,820
Cash and cash equivalents end of period	$ 20,884	$ 13,785	$ 6,680

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

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS (DEFICIT) EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 and 2007

	Preferred Shares	Preferred Stock Par Value	Common Shares Issued	Common Stock Par Value	Additional Paid-in Capital	Shares of Treasury Stock	Treasury Stock	Accumulated Deficit	Total Stockholders (Deficit) Equity	Non-Controlling Interests	
					($ in thousands, except share amounts)						
cember 31,		$	22,365,883	$ 22	$ 205,772		$	$ (90,953)	$ 114,841	$ 84,173	$
compensation					6,081				6,081	1,137	
ock grants, net s			1,187,347	2	(1)				1		
s, net										224,449	
s to ing interests										(9,470)	
								(44,154)	(44,154)	(2,904)	
cember 31,			23,553,230	24	211,852			(135,107)	76,769	297,385	
m stock			8,800,000	9	84,692				84,701	486	
compensation					1,939				1,939		
ock grants, net s			(138,587)								
stock options			10,000		100				100		
of common						21,955	(7)		(7)		
s to ing interests										(21,067)	
								(167,384)	(167,384)	(72,268)	
cember 31,			32,224,643	33	298,583	21,955	(7)	(302,491)	(3,882)	204,536	
compensation					427				427	852	
ock grants, net s			(64,522)								
								(144,922)	(144,922)	(147,398)	
cember 31,		$	32,160,121	$ 33	$ 299,010	21,955	$ (7)	$ (447,413)	$ (148,377)	$ 57,990	$

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

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization, Misappropriation and Going Concern

Organization

Quest Resource Corporation (Quest or QRCP) is a Nevada corporation. Unless the context clearly requires otherwise, references to we, us, our or the Company are intended to mean Quest Resource Corporation and its consolidated subsidiaries.

We are an integrated independent energy company involved in the acquisition, development, gathering, transportation, exploration, and production of oil and natural gas. Our principal operations and producing properties are located in the Cherokee Basin of southeastern Kansas and northeastern Oklahoma and the Appalachian Basin in West Virginia and New York. We conduct substantially all of our production operations through Quest Energy Partners, L.P. (Nasdaq: QELP) (Quest Energy or QELP) and our natural gas transportation and gathering operations through Quest Midstream Partners, L.P. (Quest Midstream or QMLP). Our Appalachian Basin operations are primarily focused on the development of the Marcellus Shale through Quest Eastern Resource LLC (Quest Eastern) and Quest Energy. Our Cherokee Basin operations are currently focused on developing coal bed methane (CBM) gas production through Quest Energy, which is served by a gas gathering pipeline network owned through Quest Midstream. Quest Midstream also owns an interstate natural gas transmission pipeline.

Misappropriation and settlement

On August 22, 2008, in connection with an inquiry from the Oklahoma Department of Securities, the boards of directors of QRCP, Quest Energy GP, LLC (Quest Energy GP), the general partner of QELP, and Quest Midstream GP, LLC (Quest Midstream GP), the general partner of QMLP, held a joint working session to address certain unauthorized transfers, repayments and re-transfers of funds (the Transfers) to entities controlled by their former chief executive officer, Mr. Jerry D. Cash. These transfers totaled approximately $10 million between 2005 and 2008.

A joint special committee comprised of one member designated by each of the boards of directors of QRCP, Quest Energy GP and Quest Midstream GP was immediately appointed to oversee an independent internal investigation of the Transfers. In connection with this investigation, other errors were identified in prior year financial statements and management and the board of directors concluded that we had material weaknesses in our internal control over financial reporting. While some of these weaknesses were remediated in 2009, several continued to exist as of December 31, 2009.

In May 2009, QRCP, QELP and QMLP entered into settlement agreements with Mr. Cash, a controlled entity of Mr. Cash, and the other owners of the entity to settle litigation related to misappropriation of funds. Under the terms of the settlement agreements, QRCP received (1) approximately $2.4 million in cash and (2) 60% of the controlled entity s interest in a natural gas well located in Louisiana and a landfill natural gas development project located in Texas. QELP received all of Mr. Cash s equity interest in STP Newco, Inc. (STP), which owns certain oil producing properties in Oklahoma, and other assets as reimbursement for costs of the internal investigation and the litigation against Mr. Cash that QELP has paid.

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We have estimated the fair value of the assets and liabilities obtained in connection with the settlement. If additional information arises, additional assets and/or liabilities may be identified and recorded. The estimated fair value of the assets and liabilities received is as follows (in thousands):

Cash, net of legal expenses	$ 2,435
Oil and gas properties	1,972
Other assets	50
Current liabilities	(326)
Long-term debt	(719)
Net assets received	$ 3,412

Recombination

QRCP is almost exclusively dependent upon distributions from its partnership interests in QELP and QMLP for revenue and cash flow. QMLP has not paid any distributions on any of its units for the third and fourth quarters of 2008 and for all of 2009. QELP suspended its distributions on its subordinated units for the third quarter of 2008 and on all units in the fourth quarter of 2008 and for all of 2009. QRCP does not expect to receive any distributions from QELP or QMLP in 2010.

Although QRCP is not currently receiving distributions from QELP or QMLP, it continues to require cash to fund general and administrative expenses, debt service requirements, capital expenditures to develop and maintain its undeveloped acreage, drilling commitments and payments to landowners necessary to maintain its oil and gas leases.

Given the liquidity challenges facing the Company, QMLP and QELP, each entity undertook a strategic review of its assets and considered various transactions to dispose of assets in order to raise additional funds for operations and/or to repay indebtedness. On July 2, 2009, QRCP, QELP and QMLP entered into a merger agreement pursuant to which all three companies would form a new publicly traded holding company (PostRock) that would wholly own all three entities (the recombination). The Company and QELP have scheduled meetings on March 5, 2010, and QMLP has scheduled a meeting on March 3, 2010, of their respective stockholders and unitholders to consider and vote upon the recombination. The closing of the recombination is subject to the satisfaction of a number of conditions, including the approval of the transaction by the stockholders of QRCP and the common unit holders of QELP and QMLP. The Company expects to consummate the recombination promptly following receipt of the requisite stockholder and unitholder approval.

Going Concern

The accompanying consolidated financial statements have been prepared assuming that we will continue as a going concern, which contemplates the realization of assets and the liquidation of liabilities in the normal course of business, though such an assumption may not be true. We have incurred significant losses from 2003 through 2009, mainly attributable to operations, the impairment of our assets, legal restructurings, financings, the legal and operational structure that existed prior to recombination, expenditures resulting from the investigation related to the misappropriation of funds discussed above under Misappropriation and Settlement and our recombination activities. While we have successfully negotiated amendments to our various credit facilities to allow us to accomplish the recombination, because the recombination was not completed as of December 31, 2009, current payment obligations under these facilities as of December 31, 2009 are $310.0 million.

As of December 31, 2009, we had a working capital deficit of approximately $273.6 million (including cash and cash equivalents of $20.9 million) caused primarily by the current portion of notes payable in the

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

aggregate principal amount of $310.0 million. Included in the $310.0 million due in 2010 is $282.5 million being classified as a current liability because it will be due on July 11, 2010 if the recombination does not occur. Were the recombination to occur before July 11, 2010, the $282.5 million would be payable on March 31, 2011.

If recombination does not occur and we are unable to modify the maturity date, we will be unable to repay our debt in 2010 without refinancing it or obtaining additional debt or equity capital. Even if the recombination occurs, we will have $27.5 million due on our credit facilities in 2010 and still be subject to financial covenants related to those facilities. We and our financial advisor have begun evaluating refinancing our credit facilities subsequent to recombination but nothing has been completed at the date of this report. There can be no assurance that we will be successful in these efforts, which raises substantial doubt as to our ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Note 2 Summary of Significant Accounting Policies

Principles of Consolidation These consolidated financial statements include our and our subsidiaries accounts. Subsidiaries in which we directly or indirectly own more than 50% of the outstanding voting securities or those in which we have 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 our consolidated financial statements. The equity of the noncontrolling interests in our majority-owned or effectively controlled subsidiaries are shown in the consolidated financial statements as noncontrolling interest . Noncontrolling interest adjusts our consolidated results of operations to reflect only our share of the earnings or losses of the consolidated subsidiary company. 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. Our most significant recurring estimates are based on remaining proved oil and gas reserves. Estimates of proved reserves are key components of our depletion rate for oil and natural gas properties and our 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.

Revenue Recognition We derive revenue from our oil and gas operations from the sale of produced oil and natural gas. We use the sales method of accounting for the recognition of oil and gas revenue. Because there is a ready market for oil and natural gas, we sell our oil and natural 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 our net revenue interests.

Gathering revenue from our pipeline operations is recognized at the time the natural gas is gathered or transported through the system and delivered to a third party. Transportation revenue from our 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 our Federal Energy Regulatory Commission (FERC) tariffs. We recognize revenues from demand charges ratably over the contract period regardless of the volume of natural gas that is transported or stored. Revenues for commodity charges are recognized when natural gas is scheduled to be delivered at the agreed upon delivery point.

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Accounts Receivable We conduct the majority of our operations in Kansas and Oklahoma and operate exclusively in the oil and gas industry. Our receivables are generally unsecured; however, we have 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 our accounts receivable and establishes an allowance for estimated uncollectible amounts. Accounts determined to be uncollectible are charged to operations in the period determined to be uncollectible. The allowance for doubtful accounts was approximately $1.2 million as of December 31, 2009 and 2008.

Inventory Inventory includes tubular goods and other lease and well equipment which we plan to utilize in our 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 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 natural gas properties are capitalized.

Oil and natural 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 natural gas properties unless the sale or disposition represents a significant quantity of proved reserves, which 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 (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 we will be required to write down the carrying value of our oil and natural gas properties increases when oil and gas prices are depressed, even if low prices are temporary. This is partially mitigated by recent changes in accounting rules requiring the use of a twelve-month average of market prices to determine the ceiling. In addition, a write-down may occur if estimates of proved reserves are substantially reduced or estimates of future development costs increase significantly.

Unevaluated Properties The costs directly associated with unevaluated oil and natural gas properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 impairments to unevaluated properties are transferred to the amortization base.

Capitalized General and Administrative Expenses Under the full cost method of accounting, a portion of general and administrative expenses that are directly attributable to our acquisition, exploration, and development activities are capitalized to our full cost pool. The capitalized costs include salaries, related fringe benefits, cost of consulting services and other costs directly associated with those activities. We capitalized general and administrative costs related to our acquisition, exploration and development activities, during the years ended December 31, 2008 and 2007 of $3.0 million and $2.3 million, respectively. We did not capitalize any general and administrative expenses in 2009 due to the significant decrease in our acquisition and development activities.

Capitalized Interest Costs We capitalize interest based on the cost of major development projects. For the years ended December 31, 2008 and 2007, we capitalized $0.6 million and $0.4 million of interest, respectively. No interest was capitalized in 2009.

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

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

Impairment Long-lived assets, such as property, and 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.

Other Assets Other assets include deferred noncurrent portion of financing costs associated with bank credit facilities and are amortized over the term of the credit facility into interest expense. Also included in other assets are contractual rights obtained in connection with the KPC Pipeline acquisition. These intangible assets are amortized over their estimated useful lives and are reviewed for impairment whenever impairment indicators are present.

Asset Retirement Obligations Asset retirement obligations associated with the retirement of a tangible long-lived asset are recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our 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

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

We own oil and natural 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. We have recorded asset retirement obligations relative to the abandonment of our interstate pipeline assets because we believe we have a legal or constructive obligation relative to asset retirements of the interstate pipeline system. We have not recorded an asset retirement obligation relating to our gathering system because we do not have any legal or constructive obligations relative to asset retirements of the gathering system.

Derivative Instruments We utilize derivative instruments in conjunction with our marketing and trading activities and to manage price risk attributable to our forecasted sales of oil and gas production.

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

Under accrual accounting, we record revenues in the period when we deliver energy commodities or products, render services, or settle contracts. Once we elect NPNS classification for a given contract, we do not subsequently change the election and treat the contract as a derivative using mark-to-market or hedge accounting. However, if we were to determine that a transaction designated as NPNS no longer qualified for the NPNS election, we would have to record the fair value of that contract on the balance sheet at that time and immediately recognize that amount in earnings.

For those derivatives that do not meet the requirements for NPNS designation nor qualify for hedge accounting, we believe that they are still effective as economic hedges of our 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 our consolidated balance sheets under the captions Derivative financial instrument assets and Derivative financial instrument liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statements of operations under the caption Gain (loss) from derivative financial instruments, which is a component of other income (expense).

We have exposure to credit risk to the extent a counterparty to a derivative instrument is unable to meet its settlement commitment. We actively monitor the creditworthiness of each counterparty and assesses the impact, if any, on our derivative positions. We do not apply hedge accounting to our 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 We are subject to legal proceedings, claims and liabilities which arise in the ordinary course of our business. We accrue for losses associated with legal claims when such losses are probable and can be reasonably estimated. These estimates are adjusted as additional information becomes available or circumstances change.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Stock-Based Compensation We grant various types of stock-based awards (including stock options and restricted stock) and account 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 our common stock on the grant date. Stock-based compensation expense is recognized over the requisite service period net of estimated forfeitures.

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

Income Taxes We record our income taxes using an asset and liability approach in accordance with the provisions of the FASB ASC 740 *Income Taxes*. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences (primarily intangible drilling costs and the net operating loss carry forward) between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under FASB ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2009 and 2008, a full valuation allowance was recorded against our net deferred tax assets.

On January 1, 2007, we adopted the provisions of FASB ASC 740 regarding the criteria an individual tax position must meet in order to be recognized in the financial statements. FASB ASC 740 provides guidance on the measurement of the income tax benefit associated with uncertain tax positions, derecognition, classification, interest and penalties and financial statement disclosure. We regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed under FASB ASC 740. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. Based on the criteria in FASB ASC 740, we did not record any liability for uncertain tax positions upon adoption of the standard. We accrue 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) by the weighted average number of shares of common stock outstanding during the period. Diluted earnings (loss) per share assumes the conversion of all potentially dilutive securities (stock options and restricted stock awards) and is calculated by dividing net income (loss) 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 Our future results will be affected by the market price of oil and natural gas. The availability of a ready market for oil and gas will depend on numerous factors beyond our 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 us to concentrations of credit risk, consist primarily of cash and accounts receivable. We place our cash investments with highly qualified financial institutions.

Risk with respect to receivables as of December 31, 2009 and 2008 arise substantially from the sales of oil and natural gas and transportation revenue from our pipeline system.

ONEOK Energy Marketing and Trading Company (ONEOK) accounted for 81% and substantially all of our oil and gas revenue for the years ended December 31, 2009 and 2008, respectively. Natural gas sales to ONEOK accounted for more than 71% of total revenue for the year ended December 31, 2007.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

We classify 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 of our derivatives are classified as Level 3 because observable market data is not available for all of the time periods for which we have 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 our derivative instruments classified as Level 2 or Level 3. We prioritize the use of the highest level inputs available in determining fair value.

Our 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 us to classify 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 June 2009, the FASB issued FASB ASC 105 *Generally Accepted Accounting Principles* (FASB ASC 105), which establishes FASB ASC as the sole source of authoritative GAAP. Pursuant to the provisions of FASB ASC 105, we have updated references to GAAP in our consolidated financial statements for the year ended December 31, 2009. The adoption of this standard did not have a material impact on our consolidated financial statements.

In March 2008, the FASB issued FASB ASC 815 *Derivatives and Hedging* (FASB ASC 815) that does not change the accounting for derivatives but does require enhanced disclosures about derivative strategies and accounting practices. We adopted these provisions effective January 1, 2009.

We adopted the provisions of FASB ASC 260 *Earnings Per Share* (FASB ASC 260), effective January 1, 2009, with respect to whether instruments granted in share-based payment transactions are considered participating securities prior to vesting and therefore included in the allocation of earnings for purposes of calculating earnings per share (EPS) under the two-class method as required by FASB ASC 260. FASB ASC 260 provides that unvested unit-based awards that contain non-forfeitable rights to dividends are participating securities and should be included in the computation of EPS. Our restricted stock units contain non-forfeitable

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

rights to dividends and thus require these awards to be included in the EPS computation. All prior periods have been conformed to the current year presentation. During periods of losses, EPS will not be impacted, as our participating securities are not obligated to share in our losses and thus, are not included in the EPS share computation. As a result of net losses reported for the year ended December 31, 2009, 2008, and 2007, adoption of these provision did not have an impact on our EPS calculations.

In December 2008, the SEC issued Release No. 33-8995, *Modernization of Oil and Gas Reporting*, which revises disclosure requirements for oil and gas companies. In addition to changing the definition and disclosure requirements for oil and gas reserves, the new rules change the requirements for determining oil and gas reserve quantities. These rules permit the use of new technologies to determine proved reserves under certain criteria and allow companies to disclose their probable and possible reserves. The new rules also require companies to report the independence and qualifications of their reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit. The new rules also require that oil and gas reserves be reported and the full cost ceiling limitation be calculated using a twelve-month average price rather than period-end prices. We implemented the new rules as of December 31, 2009. The impact of this change in prices on estimates of proved reserves was to increase depletion expense by approximately $1.0 million in the fourth quarter.

In May 2009, the FASB issued FASB ASC 855 *Subsequent Events* (FASB ASC 855). FASB ASC 855 establishes general standards of accounting for and disclosure of transactions and events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It also requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. We adopted FASB ASC 855 beginning with the quarter ended June 30, 2009. The adoption of FASB ASC 855 did not have a material impact on our consolidated financial statements.

In December 2007, the FASB issued FASB ASC 805 *Business Combinations* (FASB ASC 805). FASB ASC 805 establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree. In addition, FASB ASC 805 recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. FASB ASC 805 also establishes disclosure requirements to enable users to evaluate the nature and financial effects of the business combination. We adopted FASB ASC 805 on January 1, 2009. The adoption did not have a material effect on our results of operations, cash flows and financial position as of January 1, 2009.

In December 2007, the FASB issued FASB ASC 810 *Consolidation* (FASB ASC 810). FASB ASC 810 establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the non-controlling interest, and changes in a parent s ownership interest while the parent retains its controlling financial interest in its subsidiary. In addition, FASB ASC 810 establishes principles for valuation of retained non-controlling equity investments and measurement of gain or loss when a subsidiary is deconsolidated. FASB ASC 810 also establishes disclosure requirements to clearly identify and distinguish between interests of the parent and the interests of the non-controlling owners. We adopted FASB ASC 810 effective January 1, 2009. Under FASB ASC 810, QRCP is required to classify amounts previously presented as a minority interest liability as a component of equity in the condensed consolidated balance sheet and is required to present net income (loss) attributable to QRCP and the noncontrolling partners ownership interest separately in the condensed consolidated statement of operations. All prior periods have been reclassified to comply with FASB ASC 810.

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 3 Acquisitions and Divestitures

Acquisitions

PetroEdge On July 11, 2008, QRCP completed the acquisition of privately held PetroEdge Resources (WV) LLC (PetroEdge) in an all cash purchase for approximately $142 million in cash including transaction costs, subject to certain adjustments for working capital and certain other activity between May 1, 2008 and the closing date. The assets acquired were approximately 78,000 net acres of oil and natural gas producing properties in the Appalachian Basin with estimated net proved reserves of 99.6 Bcfe as of May 1, 2008 and net production of approximately 3.3 million cubic feet equivalent per day (Mmcfe/d). The transaction was recorded within our oil and gas production segment and was funded using the proceeds from the sale of the PetroEdge producing wellbores to Quest Cherokee, discussed below, and the proceeds of its July 8, 2008 public offering of 8,800,000 shares of common stock. At closing, QRCP sold the producing well bores to Quest Cherokee for approximately $71.2 million. The proved undeveloped reserves, unproved and undrilled acreage related to the wellbores (generally all acreage other than established spacing related to the producing well bores) and a gathering system were retained by PetroEdge and its name was changed to Quest Eastern Resource LLC. Quest Eastern is designated as operator of the wellbores purchased by Quest Cherokee and conducts drilling and other operations for our affiliates and third parties on the PetroEdge acreage. Quest Cherokee funded its purchase of the PetroEdge wellbores with borrowings under its revolving credit facility and the proceeds of a $45 million, six-month term loan.

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

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

(a) Net assets acquired by Quest Cherokee consisted of $73.4 million of proved oil and gas properties and $2.2 million of asset retirement obligations.

KPC Pipeline On November 1, 2007, QMLP completed the purchase of the KPC Pipeline for approximately $133.7 million, including transaction costs. The acquisition expanded QMLP s pipeline operations and was recorded in our natural gas pipelines segment. The KPC Pipeline is a 1,120 mile interstate gas pipeline, which transports natural gas from Oklahoma and western Kansas to the metropolitan Wichita and Kansas City markets and is one of only three pipeline systems capable of delivering gas into the Kansas City metropolitan market. The KPC system includes three compressor stations with a total of 14,680 horsepower and has a capacity of approximately 160 MMcf/d. The KPC Pipeline has supply interconnections with pipelines owned and/or operated by Enogex, Inc., Panhandle Eastern Pipeline Company and ANR Pipeline Company, allowing QMLP to transport natural gas sourced from the Anadarko and Arkoma Basins, as well as the western Kansas and Oklahoma panhandle producing regions. The acquisition was funded through the issuance of 3,750,000 common units of QMLP for $20.00 per common unit and borrowings of $58 million under QMLP s credit facility.

The total cost of the acquisition was allocated to the assets acquired and liabilities assumed based on their estimated fair values on the acquisition date. The preliminary allocation was recorded during 2007 before valuation work was completed on contract-based intangibles. After completing valuation work on the acquired

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

intangibles, a final purchase price allocation was recorded in 2008. The following table summarizes the allocation of the purchase price (in thousands):

Pipeline assets	$ 124,936
Contract-related intangible assets	9,934
Liabilities assumed	(1,145)
Purchase price	$ 133,725

Pro Forma Summary Data related to acquisitions (unaudited)

The following unaudited pro forma information summarizes the results of operations for the years ended December 31, 2008 and 2007 as if the PetroEdge acquisition had occurred on January 1, 2008 and 2007 and as if the KPC Pipeline acquisition had occurred on January 1, 2007 (in thousands):

	2008	2007
Pro forma revenue	$ 182,813	$ 143,913
Pro forma net loss	$ (246,175)	$ (60,677)
Pro forma net loss per share basic	$ (7.79)	$ (1.95)
Pro forma net loss per share diluted	$ (7.79)	$ (1.95)

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

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

Divestitures

On June 4, 2008, we acquired the right to develop, and the option to purchase, certain drilling and other rights in and below the Marcellus Shale covering approximately 28,700 net acres in Potter County, Pennsylvania for $4.0 million. On November 26, 2008, we divested of these rights to a private party for approximately $3.2 million.

On October 30, 2008, we divested of approximately 22,600 net undeveloped acres and one well in Somerset County, Pennsylvania to a private party for approximately $6.8 million.

On November 5, 2008, we divested of 50% of our interest in approximately 4,500 net undeveloped acres in Wetzel County, West Virginia to a private party for $6.1 million. Included in the sale were three wells in various stages of completion and existing pipelines and facilities. QRCP will continue to operate the property included in this joint venture. All future development costs will be split equally between us and the private party.

On February 13, 2009, we divested of 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 these divestitures were credited to the full cost pool.

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Note 4 Long-Term Debt

In 2009, QRCP and QELP entered into multiple amendments to their credit agreements that, among others, restricted the use of proceeds from certain asset sales, amended and/or waived certain representations and covenants, waived certain events of defaults related to financial covenants and collateral agreements, extended the due dates for the delivery of financial statements and extended the maturity of certain facilities. The amendments to QRCP s credit agreement on September 11, 2009 and December 17, 2009 along with the amendments to QELP s and QMLP s credit agreements on December 17, 2009 each contemplated the recombination and provided that the closing of the recombination was not an event of default. If the recombination closes, PostRock will be obligated under the existing credit agreements, which will remain at the applicable subsidiary level and continue to be secured by the existing collateral. As a result of the amendment on September 11, 2009, QRCP added an $8 million revolving credit line of credit while its term loan was extended to January 11, 2012. In connection with the amendments on December 17, 2009, QELP repaid $15 million of the $160 million outstanding on its senior revolving credit facility to reduce the amount outstanding to $145 million, and QMLP repaid $3 million of the $121.7 million outstanding on its revolving loan agreement to reduce the amount outstanding to $118.7 million. The amendments converted the QELP senior revolving credit facility and the QMLP revolving loan agreement into term loans both maturing on July 11, 2010 and not allowing additional future borrowings. QELP s $29.8 million Second Lien Loan Agreement was extended to July 11, 2010 as well. Effective with the closing of the recombination, the maturity dates of QELP s and QMLP s term loans as well as QELP s Second Lien Loan Agreement will be extended to March 31, 2011.

The following is a summary of our long-term debt at December 31, 2009 and 2008 (in thousands):

	2009	2008
Borrowings under bank senior credit facilities:		
QRCP:		
Term Loan	$ 30,108	$ 29,000
Promissory Notes	1,250	
Revolving Line of Credit	4,300	
Quest Energy:		
Quest Cherokee Credit Agreement	145,000	189,000
Second Lien Loan Agreement	29,821	41,200
QMLP:		
Credit Agreement	118,728	128,000
Notes payable to banks and finance companies	103	907
Total debt	329,310	388,107
Less current maturities included in current liabilities	310,015	45,013
Total long-term debt	$ 19,295	$ 343,094

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Aggregate maturities of long-term debt during the next five years at December 31, 2009 are as follows (in thousands):

2010	$ 310,015
2011	6,029
2012	13,255
2013	5
2014	6
Total	$ 329,310

Other Long-Term Indebtedness

Approximately $0.1 million of notes payable to banks and finance companies were outstanding at December 31, 2009 and are secured by equipment and vehicles, with payments due in monthly installments through January 2014 with interest ranging from 4.1% to 8.7% per annum.

Credit Facilities

QRCP

QRCP entered into a second amended and restated credit agreement with Royal Bank of Canada (RBC) on September 11, 2009. At the time of the amendment, QRCP s credit agreement included a term loan with principal balance of $28.3 million, an $8.0 million revolving line of credit and three promissory notes. The promissory notes included an $862,786 interest deferral note dated June 30, 2009 (representing outstanding due and unpaid interest on the term loan), a $282,500 payment-in-kind note dated May 29, 2009 (representing a 1% amendment fee payable by QRCP in connection with the fourth amendment to QRCP s credit facility), and a second $25,000 payment-in-kind note dated June 30, 2009 (representing an amendment fee payable by QRCP in connection with the fifth amendment to the credit facility). Interest on the term loan and promissory notes can be deferred at our election whereupon the deferred interest would be added to existing principal balances. On December 17, 2009, QRCP entered into a further amendment that provides for QRCP to guarantee the credit facilities of QELP and QMLP after the recombination and to pledge its ownership interests in QELP and QMLP to secure its guarantees. As of December 31, 2009, the balances, including deferred interest, of the term loan was $30.1 million and of the promissory notes was $1.3 million while the balance on the revolving line of credit was $4.3 million.

Modification of Debt. As a result of the amendment and restatement to the credit agreement on September 11, 2009, QRCP evaluated the remaining cash flows of this facility under FASB ASC 470-50-40 *Debt Modifications and Extinguishments Derecognition* (FASB ASC 470-50-40) to determine if the facility had been substantially modified as defined by the guidance. Upon determining that a substantial modification had occurred, QRCP recorded an extinguishment of prior debt and the assumption of new debt at fair value. Our analysis indicated that the fair value of the new debt facility was not materially different from the principal amount of the previous debt facility. As a result, QRCP recorded a $0.8 million loss on extinguishment of debt, which represents a write-off of unamortized debt issuance costs associated with the prior debt facility. The loss is reflected in interest expense in the consolidated statements of operations.

Interest Rate and Other Fees. Interest accrues on the QRCP term loan, the interest deferral note and the two payment-in-kind notes at the base rate plus 10.0%. The base rate varies daily and is generally the higher of the federal funds rate plus 0.50% or RBC s prime rate for such day. The revolving line of credit is non-interest bearing. QRCP will be required to pay to the lenders a facility fee equal to $2.0 million on the earlier of July 11, 2010 and the date the facility fee reduction conditions described below are satisfied. QRCP accrued a pro rata portion of this fee for the year ended December 31, 2009, based on the maturity of this facility. The

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

facility fee will be proportionately reduced if all of the following facility fee reduction conditions are satisfied: (i) repayment and termination by QRCP of the revolving line of credit, (ii) payment of the deferred quarterly principal payments under the term loan as discussed below under Payments, (iii) repayment of the interest deferral note and the two payment-in-kind notes and (iv) payment of any deferred interest under the term loan, the interest deferral note and the two payment-in-kind notes as discussed below under Payments.

Additionally, two of QRCP s subsidiaries assigned to the lenders an overriding royalty interest in the oil and gas properties owned by them in the aggregate equal to 2% of its respective working interest (plus royalty interest, if any), proportionately reduced, in its respective oil and gas properties. Each lender agreed to reconvey the overriding royalty interest (and any accrued payments owing to such lender) if on or before July 11, 2010 the facility fee reduction conditions discussed above are satisfied and the term loan (together with accrued and unpaid interest) is paid in full. Each lender also agreed to reconvey the overriding royalty interest (but not any accrued payments owing to such lender) if on or before July 11, 2010 the facility fee reduction conditions discussed above are satisfied.

Payments. Quarterly principal payments of $1.5 million on the term loan due September 30, 2009, December 31, 2009, March 31, 2010 and June 30, 2010 have been effectively deferred until July 11, 2010, at which time all $6 million will be due in order to satisfy the facility fee reduction conditions discussed above under Interest Rate and Other Fees. Commencing with the calendar quarter ended September 30, 2010, QRCP is required to make a principal repayment of $1.5 million at the end of each calendar quarter until maturity.

Maturity Dates. The maturity date of the term loan is January 11, 2012. The maturity date of the revolving line of credit, the interest deferral note and the two payment-in-kind notes is July 11, 2010. The revolving line of credit, term loan, interest deferral note and the two payment-in-kind notes may be prepaid at any time without any premium or penalty. On July 11, 2010, the total amount to be paid by QRCP under its credit agreement (assuming the facility fee reduction conditions are all satisfied on that date), based on its outstanding obligations as of December 31, 2009, would be approximately $15.4 million.

Security Interest. The QRCP credit agreement is secured by a first priority lien on QRCP s ownership interests in QELP and QMLP and the oil and gas properties owned by Quest Eastern in the Appalachian Basin, which are substantially all of QRCP s assets. The assets of QMLP, QELP and their subsidiaries are not pledged to secure the QRCP term loan. The QRCP credit agreement provides that all obligations arising under the loan documents, including obligations under any hedging agreement entered into with lenders or their affiliates (or BP Corporation North America, Inc. or its affiliates), are secured *pari passu* by the liens granted under the loan documents. In connection with the recombination, the security interest in QRCP s ownership interest in QELP and QMLP was released in order to permit QRCP to pledge such ownership interests to secure its guarantee of the credit facilities of QELP and QMLP, respectively.

Covenants. The QRCP credit agreement contains non-financial affirmative and negative covenants that are customary for credit agreements of this type. The financial covenants have been removed from the QRCP credit agreement, but QRCP and RBC agreed that if the facility fee reduction conditions discussed above under Interest Rate and Other Fees are satisfied on or before July 11, 2010, they would negotiate in good faith to amend the credit agreement to add financial covenants customary for similar credit agreements of this type.

QRCP was in compliance with all its financial covenants under the credit agreement as of December 31, 2009.

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 for a period of 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

when made, certain acts of bankruptcy or insolvency, cross defaults to other material indebtedness, and change of control. In addition, it was an event of default under QRCP s credit agreement if by January 15, 2010, QRCP had not (i) delivered to RBC evidence that the recombination has been agreed to by the lenders under QELP s and QMLP s credit agreements and (ii) delivered to RBC evidence that the board of directors of each of QRCP, QELP, QMLP and certain of their subsidiaries have approved the terms of any amendments, restatements or new credit facilities to renew, rearrange or replace the existing credit agreements of each of QELP and QMLP. This requirement was satisfied with the execution of the amendments to QELP s and QMLP s credit agreements on December 17, 2009.

QELP

Quest Cherokee credit agreement. QELP is a party, as a guarantor, to an amended and restated credit agreement with its wholly-owned subsidiary, Quest Cherokee, LLC (Quest Cherokee), as the borrower, Royal Bank of Canada (RBC), as administrative agent and collateral agent, KeyBank National Association, as documentation agent and the lenders party thereto. QELP entered into a fifth amendment to the Quest Cherokee credit agreement on December 17, 2009. QELP agreed to pay an amendment fee of 0.50% of the outstanding principal amount of the Quest Cherokee credit agreement, which fee is payable on the maturity date of the loan. The outstanding balance under the credit agreement was $145 million as of December 31, 2009, with no available capacity.

Modification of Debt. As a result of the amendment to the credit agreement on December 17, 2009, QELP evaluated the change in borrowing capacity of this facility under FASB ASC 470-50-40. Upon determining that a reduction in borrowing capacity had occurred, QELP wrote off a pro-rata portion of prior unamortized debt issuance costs in the amount of $0.8 million while capitalizing $3.4 million of direct costs associated with the current amendment. Included in this amount was $0.7 million that QELP, under the terms of the amendment, elected to defer payment until maturity of the credit agreement. The write-off is reflected in interest expense in the consolidated statements of operations.

Borrowing Base. The Quest Cherokee credit agreement consists of a three-year $145 million credit facility. In connection with the December 17, 2009 amendment, the revolving credit facility was converted to a term loan and no future borrowings are permitted under the credit facility. The maximum outstanding amount under the credit facility is tied to a borrowing base that will be redetermined by the lenders every three months taking into account the value of QELP s proved reserves. In addition, QELP and the required lenders each 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, and in certain other limited circumstances. If the borrowing base is reduced in connection with a redetermination, outstanding borrowings in excess of the new borrowing base will be required to be repaid (1) either within 30 days following receipt of notice of the new borrowing base or in two equal monthly installments beginning on or before the 30th day following receipt of notice of the new borrowing base or (2) immediately if the borrowing base is reduced in connection with a sale or disposition of certain properties in excess of 2% of the borrowing base. As of June 30, 2009, the borrowing base was $160 million (reduced from $190 million at December 31, 2008). At that time, there was a borrowing base deficiency which has been resolved but which left no remaining borrowing capacity. Effective December 17, 2009, QELP s borrowing base under its revolving credit agreement was further reduced to $145 million in connection with another borrowing base redetermination, which resulted in a borrowing base deficiency of $15 million. QELP repaid the borrowing base deficiency on December 17, 2009 in connection with the execution of the amendment to the Quest Cherokee credit agreement.

Payments. Quest Cherokee must make a prepayment within 20 business days after the end of each calendar quarter (beginning with the quarter ending March 31, 2010) in an amount equal to QELP s Excess Book Cash. Excess Book Cash is equal to book cash at the end of a quarter less the sum of the following:

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(i) restricted cash set aside for accrued royalty payments, (ii) restricted cash set aside to secure letters of credit, (iii) restricted cash set aside for accrued and unpaid taxes, (iv) quarterly estimated federal income taxes, to the extent not already reflected in (iii) above, (v) restricted cash set aside for any other amounts accrued and unpaid during the quarter and approved by the required lenders under the credit agreement, and (vi) $5 million.

Interest Rate. Interest generally accrues at either LIBOR plus 4.0% or the base rate plus 3.0%. The base rate varies daily and is generally the higher of the federal funds rate plus 0.50%, RBC s prime rate or LIBOR plus 1.25%.

Maturity Date. As of December 31, 2009, the maturity date of the Quest Cherokee credit agreement was July 11, 2010 since the recombination had not closed on that date. If the recombination is closed by July 10, 2010, the maturity date will be March 31, 2011.

Security Interest. The Quest Cherokee credit agreement is secured by a first priority lien on substantially all of the assets of QELP and its subsidiaries. All obligations arising under the loan documents, including obligations under any hedging agreement entered into with the lenders and their affiliates (or BP Corporation North America, Inc. or its affiliates), are secured *pari passu* by the liens granted under the loan documents. The Quest Cherokee credit agreement will also be secured by the guarantee of PostRock and QRCP and a pledge of all of QRCP s equity interest in QELP.

Covenants. The agreement contains affirmative and negative covenants that are customary for transactions of this type, including financial covenants that prohibit QELP, Quest Cherokee and any of their subsidiaries from:

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

permitting the interest coverage ratio of adjusted consolidated EBITDA to consolidated interest charges at any fiscal quarter-end to be less than 2.5 to 1.0 measured on a rolling four quarter basis; and

permitting the leverage ratio of consolidated funded debt to adjusted consolidated EBITDA at any fiscal quarter-end to be greater than 3.5 to 1.0 measured on a rolling four quarter basis.

QELP was in compliance with all its financial covenants under the Quest Cherokee credit agreement as of December 31, 2009.

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 for a period of 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, borrowing base deficiencies, and change of control. A change of control means (i) QRCP fails to own or to have voting control over at least 51% of the equity interest of QELP GP, (ii) any person acquires beneficial ownership of 51% or more of the equity interest in QELP; (iii) QELP fails to own 100% of the equity interests in Quest Cherokee, or (iv) QRCP undergoes a change in control (the acquisition by a person, or two or more persons acting in concert, of beneficial ownership of 50% or more of QRCP s outstanding shares of voting stock, except for a merger with and into another entity where the other entity is the survivor if QRCP s stockholders of record immediately preceding the merger hold more than 50% of the outstanding shares of the surviving entity).

The fifth amendment to the Quest Cherokee credit agreement excludes any actions to effect the recombination and the recombination itself from the definition of a change of control. The fifth amendment adds the concept of a change of control of PostRock as an event of default.

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Second Lien Loan Agreement. QELP and Quest Cherokee are parties to a $45 million second lien loan agreement. QELP entered into an eighth amendment to the second lien loan agreement on December 17, 2009. QELP agreed to pay an amendment fee of 2.10% of the outstanding principal amount of the second lien loan agreement, which fee is payable on the maturity date of the loan. The fee will be partially forgiven if the second lien term loan is repaid in full on or before February 28, 2011. The outstanding balance under the loan was $29.8 million as of December 31, 2009.

Modification of Debt. As a result of the eighth amendment to the second lien loan on December 17, 2009, QELP evaluated the remaining cash flows of this facility under FASB ASC 470-50-40 and determined that facility had not been substantially modified. An additional $0.9 million of direct costs associated with the amendment was capitalized. Included in this amount was $0.6 million that QELP, under the terms of the amendment, elected to defer payment until maturity of the loan.

Interest Rate. Interest accrues under the second lien loan agreement at either LIBOR plus 11.0% (with a LIBOR floor of 3.5%) or the base rate plus 10.0%. The base rate varies daily and is generally the higher of the federal funds rate plus 0.5%, RBC s prime rate or LIBOR plus 1.25%. Amounts due under the second lien loan agreement may be prepaid without any premium or penalty, at any time. QELP may elect to defer the payment of a portion of the interest (at the rate of up to 2%) until maturity. If any amount is outstanding under the Quest Cherokee credit agreement, such interest amount must be deferred. Deferred interest will bear interest.

Payments. No prepayments may be made on the second lien term loan while the Quest Cherokee credit agreement is outstanding. After the Quest Cherokee credit agreement is paid in full, Quest Cherokee must make a prepayment within 20 business days after the end of each calendar quarter (beginning with the quarter ending March 31, 2010) in an amount equal to QELP s Excess Book Cash.

Maturity Date. As of December 31, 2009, the maturity date of the second lien loan agreement was July 11, 2010 since the recombination had not closed on that date. If the recombination is closed by July 10, 2010, the maturity date will be March 31, 2011.

Security Interest. The second lien loan agreement is secured by a second priority lien on substantially all of the assets of QELP and its subsidiaries. The second lien loan agreement is also secured by the guarantee of PostRock and QRCP (which is subordinated to the guarantees of the Quest Cherokee credit agreement and the QMLP credit agreement) and a second lien pledge of all of QRCP s equity interest in QELP.

Covenants. The second lien loan agreement contains affirmative and negative covenants that are customary for credit agreements of these types, including financial covenants that prohibit QELP, Quest Cherokee and any of their subsidiaries from:

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

permitting the interest coverage ratio of adjusted consolidated EBITDA to consolidated interest charges at any fiscal quarter-end to be less than 2.5 to 1.0 measured on a rolling four quarter basis; and permitting the leverage ratio of consolidated funded debt to adjusted consolidated EBITDA at any fiscal quarter-end to be greater than 3.5 to 1.0 measured on a rolling four quarter basis.

The second lien loan agreement contains an additional financial covenant that prohibits QELP, Quest Cherokee, and any of their subsidiaries from permitting the total reserve leverage ratio (ratio of total proved reserves to consolidated funded debt) at any fiscal quarter-end to be less than 1.5 to 1.0.

QELP was in compliance with all its financial covenants under the second lien loan agreement as of December 31, 2009.

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Events of Default. Events of default under the second lien loan agreement 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 for a period of 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 and change of control. A change of control means (i) QRCP fails to own or to have voting control over at least 51% of the equity interest of QELP GP, (ii) any person acquires beneficial ownership of 51% or more of the equity interest in QELP; (iii) QELP fails to own 100% of the equity interests in Quest Cherokee, or (iv) QRCP undergoes a change in control (the acquisition by a person, or two or more persons acting in concert, of beneficial ownership of 50% or more of QRCP s outstanding shares of voting stock, except for a merger with and into another entity where the other entity is the survivor if QRCP s stockholders of record immediately preceding the merger hold more than 50% of the outstanding shares of the surviving entity).

The eighth amendment to the Quest Cherokee credit agreement excludes any actions to effect the recombination and the recombination itself from the definition of a change of control. The eighth amendment adds the concept of a change of control of PostRock as an event of default.

QMLP

QMLP and Bluestem, as borrowers, entered into a third amendment to the amended and restated QMLP credit agreement on December 17, 2009. The borrowers agreed to pay an amendment fee of 0.50% of the outstanding principal amount of the QMLP credit agreement, which fee is payable on the maturity date of the loan. In connection with the December 17, 2009 amendment, the QMLP credit agreement was converted to a term loan and no future borrowings are permitted under the QMLP credit agreement. As of December 31, 2009, the outstanding principal amount of the QMLP credit agreement was $118.7 million with $1.0 million of capacity available only for letters of credit.

Modification of Debt. As a result of the amendment to the credit agreement on December 17, 2009, QMLP evaluated the change in borrowing capacity of this facility under FASB ASC 470-50-40. Upon determining that a reduction in borrowing capacity had occurred, QMLP wrote off a pro-rata portion of prior unamortized debt issuance costs in the amount of $1.9 million while capitalizing $2.1 million of direct costs associated with the amendment. Included in this amount was $0.6 million that QMLP, under the terms of the amendment, elected to defer payment until maturity of the credit agreement. The write-off is reflected in interest expense in the consolidated statements of operations.

Interest Rate. Interest accrues at either LIBOR plus a margin ranging from 2.0% to 3.5% (depending on the total leverage ratio) or the base rate plus a margin ranging from 1.0% to 2.5% (depending on the total leverage ratio), at the borrowers option. The base rate is generally the higher of the federal funds rate plus 0.5%, RBC s prime rate or LIBOR plus 1.25%.

Payments. There are no scheduled principal payments prior to the maturity date.

Maturity Dates. As of December 31, 2009, the maturity date of the QMLP credit agreement was July 11, 2010 since the recombination had not closed on that date. If the recombination is closed by July 10, 2010, the maturity date will be March 31, 2011.

Security Interest. The QMLP credit agreement is secured by a first priority lien on substantially all of the assets of QMLP and its subsidiaries. The QMLP credit agreement is also secured by the guarantee of PostRock and QRCP and a pledge of all of QRCP s equity interest in QMLP.

Covenants. The QMLP credit agreement contains affirmative and negative covenants that are customary for credit agreements of this type.

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The QMLP credit agreement contains financial covenants that prohibit QMLP and any of its subsidiaries from:

- permitting the interest coverage ratio (ratio of adjusted consolidated EBITDA to consolidated interest charges) on a rolling four quarter basis to be less than 2.50 to 1.00 for the fiscal quarter ending on or prior to March 31, 2010 and increasing to 2.75 to 1.00 for each fiscal quarter end thereafter; and

- permitting the total leverage ratio (ratio of adjusted consolidated funded debt to adjusted consolidated EBITDA) on a rolling four quarter basis to be greater than 5.00 to 1.00 for the fiscal quarter ending on or prior to March 31, 2010 and decreasing to 4.50 to 1.00 for each fiscal quarter end thereafter.

QMLP was in compliance with all its financial covenants under the QMLP credit agreement as of December 31, 2009.

Events of Default. Events of default under the QMLP credit agreement 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 for a period of 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, and change of control. Under the QMLP credit agreement a change of control means (i) QRCP fails to own or to have voting control over, at least 51% of the equity interest of QMGP; (ii) any person acquires beneficial ownership of 51% or more of the equity interest in QMLP; (iii) QMLP fails to own 100% of the equity interests in Bluestem Pipeline, LLC (Bluestem) or (iv) QRCP undergoes a change in control (the acquisition by a person, or two or more persons acting in concert, of beneficial ownership of 50% or more of QRCP s outstanding shares of voting stock, except for a merger with and into another entity where the other entity is the survivor if QRCP s stockholders of record immediately preceding the merger hold more than 50% of the outstanding shares of the surviving entity).

The third amendment to the QMLP Credit Agreement excludes any actions to effect the recombination and the recombination itself from the definition of a change of control. The third amendment adds the concept of a change of control of PostRock as an event of default.

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5 Property

Oil and natural gas properties, pipeline assets and other property and equipment were comprised of the following as of December 31, 2009 and 2008 (in thousands):

	2009	2008
Oil and natural gas properties under the full cost method of accounting:		
Properties being amortized	$ 205,199	$ 299,629
Properties not being amortized	596	10,108
Total oil and natural gas properties, at cost	205,795	309,737
Less: accumulated depletion, depreciation and amortization	(165,317)	(137,200)
Oil and natural gas properties, net	$ 40,478	$ 172,537
Pipeline assets, at cost	$ 170,737	$ 333,966
Less: accumulated depreciation	(34,720)	(23,527)
Pipeline assets, net	$ 136,017	$ 310,439
Other property and equipment at cost	$ 33,704	$ 33,994
Less: accumulated depreciation	(14,271)	(10,131)
Other property and equipment, net	$ 19,433	$ 23,863

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

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

For the years ended December 31, 2009, 2008 and 2007, depletion, depreciation and amortization expense (excluding impairment amounts discussed below) on oil and natural gas properties amounted to $28.3 million, $50.4 million and $31.7 million, respectively; depreciation expense on pipeline assets amounted to $12.2 million, $16.2 million and $5.8 million, respectively; and depreciation expense on other property and equipment amounted to $3.5 million,

$3.8 million and $2.3 million, respectively.

Impairment of oil and natural gas properties As of December 31, 2009, our net book value of oil and natural gas properties was below the full cost ceiling. Accordingly, a provision for impairment was not required in the fourth quarter of 2009. We recorded an impairment of $102.9 million in the first quarter of 2009 as a result of declines in the prevailing market prices of oil and natural gas at that time. We recorded an impairment for the year ended December 31, 2008, of $298.9 million.

Impairment of pipeline related assets During the fourth quarter of 2009, we determined that our pipeline assets and intangibles could be impaired. We were unable to negotiate a new contract with one of our major customers, Missouri Gas and Electric (MGE). Our existing contract with MGE expired in October 2009, although prior to the expiration we believed that the contract could be extended or renegotiated with MGE or replaced by another customer.

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In connection with amendments to our credit facilities in the fourth quarter of 2009, the amendment imposed limits on our capital expenditures and consequently on our ability to further develop acreage in the Cherokee Basin, the geographic region served by our Bluestem gathering pipeline. This resulted in lower projected future revenue to our gathering pipeline system.

The impairment test under FASB ASC 360 is a two-step test. Step one requires comparing the undiscounted cash flows to the carrying value of the asset group. An asset group is the lowest level in which cash flows are available. We determined that we have two asset groups, Bluestem and KPC. If the undiscounted cash flows exceed the carrying value of the assets, no further analysis is required, as the assets are not deemed to be impaired. Bluestem and KPC failed step one. Step two requires the comparison of the carrying value to the fair value of the asset group. In order to determine the fair value, we utilized a market approach for KPC and an income approach for Bluestem. Utilizing these approaches, the carrying value of the asset groups exceeded the market value by approximately $164.7 million and we recorded an impairment for such amount. In addition, we determined that our customer-related contracts, held by KPC and presented as intangible assets on the consolidated balance sheet, were also impaired and recognized an impairment of $1.0 million on our intangible assets. No such impairment was required at December 31, 2008.

Note 6 Noncontrolling Interests

A rollforward of noncontrolling interest balances related to QRCP s investments in QELP and QMLP for the years ended December 31, 2009 and 2008, is as follows (in thousands):

	2009	2008
Quest Energy:		
Beginning of year	$ 58,666	$ 145,364
Contributions, net		
Distributions		(13,438)
Interest in earnings (loss)	(43,553)	(73,295)
Stock compensation expense related to QELP unit-based awards	237	35
End of year	$ 15,350	$ 58,666
Quest Midstream:		
Beginning of year	$ 145,870	$ 152,021
Contributions, net		
Distributions		(7,629)
Interest in earnings (loss)	(103,845)	1,027
Stock compensation expense related to QMLP unit-based awards	615	451
End of year	$ 42,640	$ 145,870
Total non-controlling interest at end of year	$ 57,990	$ 204,536

QELP

During November 2007, QELP completed its initial public offering of 9,100,000 common units (representing a 42.1% limited partner interest) for net proceeds of $151.3 million ($163.8 million less $12.5 million for underwriting discounts, structuring fees and offering costs). QELP was formed by us to own, operate, acquire and develop our oil and gas production operations in the Cherokee Basin. We contributed assets to QELP in exchange for an aggregate 55.9% limited partner interest (consisting of common and subordinated limited partner units) in QELP, a 2% general partner interest and incentive distribution rights (IDRs). IDRs entitle the holder to specified increasing percentages of cash distributions as QELP s per-unit

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QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cash distributions increase. In addition, we maintained control over the assets owned by QELP through sole indirect ownership of the general partner interests. Net proceeds from the offering were used to refinance a portion of the existing debt secured by the assets contributed to QELP.

The QELP common units had preference over the subordinated units with respect to cash distributions. Accordingly, all proceeds from the sale of the common units were recorded as noncontrolling interest on the consolidated balance sheets.

During the first and second quarters of 2008, QELP paid distributions of $0.41 per unit and $0.43 per unit on all outstanding units. In the third quarter of 2008 distributions of $0.40 per unit were paid on only the common units and a proportionate distribution on the general partner units. No further distributions have been paid since that time.

The results of operations and financial position of QELP are included in our consolidated financial statements. The portion of QELP s results that is attributable to common units held by the public is recorded as income (loss) attributable to non-controlling interests.

In December 2009, QELP granted 1,003,414 restricted common units to employees of QELP, QRCP and QMLP. These restricted unit grants will be assumed by PostRock in the recombination and are subject to pro rata vesting over a period of four years. During the vesting period, the fair value of the unit awards granted is recognized pro rata as compensation expense in general and administrative expenses. The grant date fair value of these awards was $1.4 million, of which $0.2 million was recognized in expense as of December 31, 2009.

QMLP

During 2006, we formed QMLP to own, operate, acquire and develop midstream assets. We transferred pipeline assets and certain associated liabilities to QMLP as a capital contribution in exchange for 4,900,000 Class B subordinated units and 35,134 Class A subordinated units, which represented an aggregate 35.4% limited partner interest in QMLP as of December 31, 2009, as well as an 85% interest in the general partner of QMLP, which owned a 2% general partner interest and incentive distribution rights. The IDRs entitled the holder to specified increasing percentages of cash distributions as QMLP s per-unit cash distributions increase. At the same time, QMLP issued 4,864,866 common units to private investors for net proceeds of $84.2 million ($90 million less $5.8 million for placement fees and offering costs).

In November 2007, QMLP completed the purchase of the KPC Pipeline for a purchase price of approximately $133 million in cash, subject to adjustment for working capital at closing, and assumed liabilities of approximately $1.2 million. In connection with this acquisition, QMLP issued 3,750,000 common units to private investors for approximately $75 million of gross proceeds ($73.6 million after offering costs). As a result of these two issuances, private investors owned an approximate 62.6% limited partner interest in QMLP as of December 31, 2009. We maintained control over the assets owned by QMLP through its majority ownership interest in QMLP s general partner.

The QMLP common units had preference over the subordinated units with respect to cash distributions. Accordingly, all proceeds from the sale of the common units were recorded as noncontrolling interest on the consolidated balance sheet.

During the first and second quarters of 2008, QMLP paid distributions of $0.425 per unit each quarter on only the common units and a proportionate distribution on the general partner units. No further distributions have been paid since that time.

The results of operations and financial position of QMLP are included in our consolidated financial statements. The portion of QMLP s results of operations that is attributable to common units held by the private investors (units we do not hold) is recorded as noncontrolling interests.

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In December 2009, QMLP granted 711,314 restricted common units to employees of QMLP, QRCP and QELP. These restricted unit grants will be assumed by PostRock in the recombination and are subject to pro rata vesting over a period of four years. During the vesting period, the fair value of the unit awards granted is recognized pro rata as compensation expense in general and administrative expenses. The grant date fair value of these awards was $1.4 million, of which $0.2 million was recognized in expense as of December 31, 2009.

Note 7 Derivative Financial Instruments

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

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

We account for our derivative financial instruments in accordance with FASB ASC 815 *Derivatives and Hedging* (FASB ASC 815). FASB ASC 815 requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. ASC Topic 815 requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met, or exemptions for normal purchases and normal sales (NPNS) as permitted by FASB ASC 815 exist. We do not designate our derivative financial instruments as hedging instruments for financial accounting purposes, and, as a result, we recognize the change in the respective instruments fair value currently in earnings. In accordance with FASB ASC 815, the table below outlines the classification of our derivative financial instruments on our consolidated balance sheets and their financial impact in our consolidated statement of operations as of December 31, 2009 and 2008 (in thousands):

Fair Value of Derivative Financial Instruments

Derivative Financial Instruments	Balance Sheet location	December 31, 2009	December 31, 2008
Commodity contracts	Current derivative financial instrument asset	$ 10,624	$ 42,995
Commodity contracts	Long-term derivative financial instrument asset	18,955	30,836

Commodity contracts	Current derivative financial instrument liability	(1,447)	(12)
Commodity contracts	Long-term derivative financial instrument liability	(8,569)	(4,230)
		$ 19,563	$ 69,589

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gains and losses associated with derivative financial instruments related to gas and oil production were as follows for the years ended December 31, 2009, 2008, and 2007 (in thousands):

	2009	2008	2007
Realized gain (loss)(1)	$ 98,148	$ (6,388)	$ 7,279
Unrealized gain (loss)	(50,026)	72,533	(5,318)
Total gain from derivative financial instruments	$ 48,122	$ 66,145	$ 1,961

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

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

	Year Ending December 31, 2010	2011	2012	Thereafter	Total
	($ in thousands, except volumes and per unit data)				
Natural Gas Swaps:					
Contract volumes (Mmbtu)	16,129,060	13,550,302	11,000,004	9,000,003	49,679,369
Weighted-average fixed price per Mmbtu	$ 6.26	$ 6.80	$ 7.13	$ 7.28	$ 6.78
Fair value, net	$ 10,424	$ 7,530	$ 6,662	$ 4,763	$ 29,379
Natural Gas Basis Swaps:					
Contract volumes (Mmbtu):	3,630,000	8,549,998	9,000,000	9,000,003	30,180,001
Weighted-average fixed price per Mmbtu	$ (0.63)	$ (0.67)	$ (0.70)	$ (0.71)	$ (0.69)
Fair value, net	$ (1,402)	$ (2,973)	$ (2,879)	$ (2,717)	$ (9,971)
Crude Oil Swaps:					
Contract volumes (Bbl)	30,000				30,000
Weighted-average fixed price per Bbl	$ 87.50	$	$	$	$ 87.50
Fair value, net	$ 155	$	$	$	$ 155
Total fair value, net	**$ 9,177**	**$ 4,557**	**$ 3,783**	**$ 2,046**	**$ 19,563**

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables summarize the estimated volumes, fixed prices and fair value attributable to gas derivative contracts as of December 31, 2008:

	Year Ending December 31, 2009	2010	2011	Thereafter	Total
	($ in thousands, except volumes and per unit data)				
Natural Gas Swaps:					
Contract volumes (Mmbtu)	14,629,200	12,499,060	2,000,004	2,000,004	31,128,268
Weighted-average fixed price per Mmbtu	$ 7.78	$ 7.42	$ 8.00	$ 8.11	$ 7.67
Fair value, net	$ 38,107	$ 14,071	$ 2,441	$ 2,335	$ 56,954
Natural Gas Collars:					
Contract volumes (Mmbtu):	750,000	630,000	3,549,996	3,000,000	7,929,996
Weighted-average fixed price per Mmbtu:					
Floor	$ 11.00	$ 10.00	$ 7.39	$ 7.03	$ 7.79
Ceiling	$ 15.00	$ 13.11	$ 9.88	$ 7.39	$ 9.52
Fair value, net	$ 3,630	$ 1,875	$ 3,144	$ 2,074	$ 10,723
Total Natural Gas Contracts:					
Contract volumes (Mmbtu)	15,379,200	13,129,060	5,550,000	5,000,004	39,058,264
Weighted-average fixed price per Mmbtu	$ 7.94	$ 7.55	$ 7.61	$ 7.44	$ 7.70
Fair value, net	$ 41,737	$ 15,946	$ 5,585	$ 4,409	$ 67,677
Crude Oil Swaps:					
Contract volumes (Bbl)	36,000	30,000			66,000
Weighted-average fixed price per Bbl	$ 90.07	$ 87.50	$	$	$ 88.90
Fair value, net	$ 1,246	$ 666	$	$	$ 1,912
Total fair value, net	**$ 42,983**	**$ 16,612**	**$ 5,585**	**$ 4,409**	**$ 69,589**

Note 8 Financial Instruments

Our financial instruments include commodity derivatives, debt, cash, receivables and payables. The carrying value of our debt approximates fair value as of December 31, 2009 and 2008. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of those instruments.

Fair Value The following table sets forth, by level within the fair value hierarchy, our assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2009 and 2008 (in thousands):

	Netting and

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

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2008		Level 1	Level 2	Level 3	Netting and Cash Collateral*	Total Net Fair Value
Derivative financial instruments	assets	$	$ 8,866	$ 64,883	$ (4,160)	$ 69,589
Derivative financial instruments	liabilities	$	$ (224)	$ (3,936)	$ 4,160	$
Total		$	$ 8,642	$ 60,947	$	$ 69,589

* Amounts represent the effect of legally enforceable master netting agreements between us and its counterparties and the payable or receivable for cash collateral held or placed with the same counterparties.

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

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

In certain instances, we may utilize internal models to measure the fair value of our derivative instruments. Generally, we use similar models to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the assets or liabilities, and market-corroborated inputs, which are inputs derived principally from or corroborated by observable market data by correlation or other means.

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 year ended December 31, 2009 (in thousands):

Balance at beginning of year	$ 60,947
Realized and unrealized gains included in earnings	29,202
Purchases, sales, issuances, and settlements	(88,619)
Transfers into and out of Level 3	

Balance as of December 31, 2009	$	1,530

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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 our balance sheet. The following table describes the changes to our assets retirement liability for the years ending December 31, 2009 and 2008 (in thousands):

	2009	2008
Asset retirement obligations at beginning of year	$ 5,922	$ 2,938
Liabilities incurred	78	134
Liabilities settled	(13)	(22)
Acquisition of PetroEdge		2,193
Accretion	565	388
Revisions in estimated cash flows		291
Asset retirement obligations at end of year	$ 6,552	$ 5,922

Note 10 Stockholders Equity

Stockholders Rights Plan On May 31, 2006, the board of directors of QRCP declared a dividend distribution of one right for each share of common stock of QRCP, and the dividend was distributed on June 15, 2006. The rights are governed by a Rights Agreement, dated as of May 31, 2006, between QRCP and Computershare (formerly UMB Bank, n.a.). Pursuant to the Rights Agreement, each right entitles the registered holder to purchase from QRCP one one-thousandth of a share (Unit) of Series B Junior Participating Preferred Stock, $0.001 par value per share, at a purchase price of $75.00 per Unit. The rights, however, will not become exercisable unless and until, among other things, any person acquires 15% or more of the outstanding shares of common stock of QRCP. If a person acquires 15% or more of the outstanding stock of QRCP (subject to certain exceptions more fully described in the Rights Agreement), each right will entitle the holder (other than the person who acquired 15% or more of the outstanding common stock) to purchase common stock of QRCP having a value equal to twice the exercise price of a right. The rights are redeemable under certain circumstances at $0.001 per right and will expire, unless earlier redeemed, on May 31, 2016. The rights plan will be terminated upon consummation of the recombination.

Stock Awards Under the 2005 Omnibus Stock Award Plan (as amended) (the Plan) there are available for issuance 2,700,000 shares of QRCP s Common Stock. The shares that have been granted are subject to pro rata vesting which ranges from 0 to 4 years. During this vesting period, the fair value of the stock awards granted is recognized pro rata as compensation expense in general and administrative expenses. For the years ended December 31, 2009, 2008 and 2007, QRCP recognized $0.3 million, $1.9 million and

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$6.1 million, of compensation expense related to stock awards. A summary of changes in the non-vested restricted shares for the years ending December 31, 2009, 2008 and 2007 is presented below:

	Number of Non-Vested Restricted Shares	Weighted Average Grant-Date Fair Value
Non-vested restricted shares at December 31, 2006	117,000	$ 9.43
Granted	1,192,968	8.71
Vested	(222,472)	9.21
Forfeited	(5,621)	8.67
Non-vested restricted shares at December 31, 2007	1,081,875	$ 8.69
Granted	405,362(a)	7.50
Vested	(470,912)	8.28
Forfeited	(533,949)	8.75
Non-vested restricted shares at December 31, 2008	482,376	$ 8.01
Granted	1,108,696(b)	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

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

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

As of December 31, 2009, total unrecognized stock-based compensation expense related to non-vested restricted shares was $0.5 million, which is expected to be recognized over a weighted average period of approximately 1.95 years.

Stock Options The Plan also provides for the granting of options to purchase shares of QRCP s common stock. QRCP has granted stock options to employees and non-employees under the Plan. The options expire 10 years following the date of grant.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of changes in stock options outstanding during the years ending December 31, 2009, 2008, and 2007 is presented below:

	Stock Options	Weighted Average Exercise Price per Share
Options outstanding at December 31, 2006	150,000	$ 10.00
Granted	100,000	10.05
Exercised		
Forfeited		
Options outstanding at December 31, 2007	250,000	10.00
Granted	300,000	0.63
Exercised	(10,000)	10.05
Converted	(140,000)	10.03
Options outstanding at December 31, 2008	400,000	2.98
Granted	300,000	0.62
Exercised		
Forfeited	(30,000)	10.00
Options outstanding at December 31, 2009	670,000	1.61
Options exercisable at December 31, 2009	370,000	$ 2.41

The weighted average grant date fair value of stock options granted during 2009, 2008 and 2007 were $0.45, $0.54, and $7.96, respectively.

The weighted average remaining term of options outstanding and options exercisable at December 31, 2009 was 8.57 and 8.20 years, respectively. Options outstanding and options exercisable at December 31, 2009 had no aggregate intrinsic value.

QRCP 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. QRCP used the following weighted-average assumptions to estimate the fair value of stock options granted during the years ending December 31, 2009, 2008 and 2007:

	2009	**2008**	**2007**
Expected option life years	10	10	10
Volatility	101.2%	69.8%	61.1%
Risk-free interest rate	4.93%	5.42%	5.35%
Dividend yield			
Fair value	$ 0.45	$0.41 - $0.61	$ 7.96

For the years ended December 31, 2009, 2008 and 2007, we recognized $0.2 million, $0.2 million and, $0.5 million of compensation expense related to stock options. As of December 31, 2009, there was $0.1 million of total unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted average period of 1.27 years.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Earnings (Loss) per Share A reconciliation of the numerator and denominator used in the basic and diluted per share calculations for the years ending December 31, 2009, 2008 and 2007, is as follows (in thousands, except per share data):

	2009	2008	2007
Basic earnings per share:			
Net income (loss) available to common shareholders	$ (144,922)	$ (167,384)	$ (44,154)
Shares:			
Weighted average number of common shares outstanding	31,833	27,011	22,379
Basic earnings (loss) per share:			
Total basic earnings (loss) per share	$ (4.55)	$ (6.20)	$ (1.97)
Diluted earnings per share:			
Net income (loss) available to common shareholders	$ (144,922)	$ (167,384)	$ (44,154)
Shares:			
Weighted average common shares and common stock equivalents	31,833	27,011	22,379
Diluted earnings (loss) per share:			
Total diluted earnings (loss) per share	$ (4.55)	$ (6.20)	$ (1.97)

Because we have reported net losses in the years ended December 31, 2009, 2008 and 2007, weighted average restricted stock awards of 384,908; 871,344; and 781,540 common shares, respectively, and the effect of outstanding options to purchase 683,479; 193,288; and 188,082 common shares, respectively, were excluded from the computation of net loss per share because their effect would have been antidilutive.

Note 11 Income Taxes

We have recorded no provision or benefit for income taxes for the years ended December 31, 2009, 2008 and 2007.

A reconciliation of federal income taxes at the statutory federal rates to our actual provision for income taxes for the years ended December 31, 2009, 2008 and 2007 are as follows (in thousands):

	2009	2008	2007
Income tax expense (benefit) at statutory rate	$ (50,723)	$ (58,584)	$ (15,454)

State income tax expense (benefit), net of federal	(3,131)	(3,789)	(956)
Other	2,548	300	752
Change in valuation allowance	51,306	62,073	15,658
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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

evidence that existed as of each reporting period, we recorded a full valuation allowance against our net deferred tax asset as of December 31, 2009, 2008, and 2007.

Deferred tax assets and liabilities as of December 31, 2009 and 2008 were as follows (in thousands):

	2009	2008
Current deferred income tax assets:		
Commodity derivative expense recorded for book, not for tax	$	$
Accrued liabilities		219
Allowance for bad debts		78
Unearned revenue		236
Total current deferred income tax assets		533
Noncurrent deferred income tax assets:		
Partnership basis differences	49,889	7,401
Property and equipment basis differences	19,284	18,434
Net operating loss carryforwards	89,523	72,635
Other tax credit carryforwards	34	4,352
Misappropriation of assets		3,728
Other expense recorded for books, not for tax	979	1,320
Total noncurrent deferred income tax assets	159,709	107,870
Total deferred income tax assets	159,709	108,403
Total current deferred income tax liabilities		
Total noncurrent deferred income tax liabilities		
Total deferred income tax liabilities		
Net deferred income tax assets	159,709	108,403
Valuation allowance	(159,709)	(108,403)
Total deferred tax asset (liability)	$	$

We have net operating loss (NOL) carryforwards of approximately $240 million at December 31, 2009 that are available to reduce future U.S. taxable income. If not utilized, such carryforwards will expire from 2021 through 2029.

Our ability to utilize NOL carryforwards to reduce future federal taxable income and federal income tax of the Company is subject to various limitations under the Internal Revenue Code of 1986, as amended (the Code). 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 the QRCP during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of any 5% stockholders of QRCP.

QRCP completed a private placement of its common stock on November 14, 2005. In connection with this offering, 15,258,144 shares of common stock were issued. This issuance may constitute an owner shift as defined in the Regulations under 1.382-2T. Accordingly, this event may subject approximately $40 million of NOLs to limitations under Section 382 of the Code. The Company believes that its Section 382 annual limitation applicable to NOLs incurred prior to the owner shift should, otherwise, be sufficient to allow such NOLs to be utilized prior to their expiration. NOLs incurred after November 14, 2005 through December 31,

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2009 are not currently limited under Section 382. The Company is currently assessing whether the Recombination will cause an ownership shift for the purposes of Section 382 and whether the NOL carryforwards that exist on the date of the Recombination will be limited.

FASB ASC 740-10 provides guidance for recognizing and measuring uncertain tax positions. Based upon the provisions of FASB ASC 740-10, we recorded no amounts for uncertain tax benefits upon adoption of the standard and have no amounts recorded for uncertain tax benefits as of December 31, 2009. Accordingly, there has been no change in unrecognized tax benefits during the year. We file income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The tax years ended December 31, 2008, 2007 and 2006 remain open for examination by the relevant taxing authorities. In addition, our tax returns for the tax years ended December 31, 2001, through December 31, 2005, 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. Our policy is to recognize interest and penalties, if any, related to unrecognized tax positions as income tax expense.

Note 12 Commitments and Contingencies

Litigation We are subject, from time to time, to certain legal proceedings and claims in the ordinary course of conducting our business. We 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. Except for those legal proceedings listed below, we believe there are no pending legal proceedings in which we are currently involved which, if adversely determined, could have a material adverse effect on our financial position, results of operations or cash flow. We intend to defend vigorously against the claims described below. We are unable to predict the outcome of these proceedings or reasonably estimate a range of possible loss that may result.

Federal Securities Class Actions

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

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

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

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

Four putative class action complaints were filed in the United States District Court for the Western District of Oklahoma naming QRCP, QELP and QEGP and certain of their then current and former officers and directors as defendants. The complaints were filed by certain stockholders on behalf of themselves and other stockholders who purchased QRCP common stock between May 2, 2005 and August 25, 2008 and QELP common units between November 7, 2007 and August 25, 2008. The complaints assert claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as amended (the Exchange Act), and Rule 10b-5 promulgated thereunder, and Sections 11 and 15 of the Securities Act of 1933. The complaints allege that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material facts concerning certain unauthorized transfers of funds from subsidiaries of QRCP to

QUEST RESOURCE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaints also allege that, as a result of these actions, QRCP s stock price and the unit price of QELP was artificially inflated during the class period. On December 29, 2008, the court consolidated these complaints as *Michael Friedman, individually and on behalf of all others similarly situated v. Quest Energy Partners LP, Quest Energy GP LLC, Quest Resource Corporation, Jerry Cash, and David E. Grose*, Case No. 08-cv-936-M, in the Western District of Oklahoma. On September 24, 2009, the court appointed lead plaintiffs for each of the QRCP class and the QELP class. The lead plaintiffs must file a consolidated amended complaint within 60 days after being appointed. On October 13, 2009, the plaintiffs filed a motion for partial modification of the Private Securities Litigation Reform Act of 1995 discovery stay, which the defendants opposed and which the court denied on December 15, 2009. On November 4, 2009, the court granted the lead plaintiffs unopposed request to file separate consolidated amended complaints. The court ordered that all pleadings and filings for the QELP class be filed under *Friedman v. Quest Energy Partners, LP, et al.*, case no. CIV-08-936-M, and all pleadings and filings for the QRCP class be filed under *Jents v. Quest Resource Corporation, et al.*, case no. CIV-08-968-M. The QELP lead plaintiffs filed a consolidated complaint on November 10, 2009. The consolidated complaint names as additional defendants David C. Lawler, Gary Pittman, Mark Stansberry, Murrell Hall, McIntosh & Co. PLLP, and Eide Bailly LLP. The QRCP lead plaintiffs filed a consolidated complaint on December 7, 2009, which names Murrell, Hall, McIntosh & Co. PLLP, Eide Bailly LLP, and various former QRCP directors as additional defendants. On December 23, 2009, QRCP and David C. Lawler filed a motion to dismiss the *Friedman* complaint, and on December 28, 2009, QELP, QEGP, Gary Pittman and Mark Stansberry filed a motion to dismiss the *Friedman* complaint. On January 21, 2010, QRCP and the individual director defendants filed a motion to dismiss the *Jents* complaint. No response to the motion to dismiss has yet been filed in either proceeding. On February 2, 2010, a mediation was held among the parties. A second round of the mediation is currently scheduled for April 2, 2010. In the event that the cases are not settled, then the companies intend to defend vigorously against the plaintiffs claims in both the *Friedman* and *Jents* actions.

QRCP and QELP have received letters from their directors and officers insurance carriers reserving their rights to limit or preclude coverage under various provisions and exclusions in the policies, including for the committing of a deliberate criminal or fraudulent act by a past, present, or future chief executive officer or chief financial officer. On October 27, 2009, QELP received written confirmation from its directors and officers liability insurance carrier stating that it will not provide insurance coverage to QELP based on Mr. Cash s alleged written admission that he engaged in acts for which coverage is excluded. The carrier also reserved its rights to deny coverage under various other provisions and exclusions in the policies. QELP disagrees with the insurer carrier s coverage position and continues to evaluate its options regarding the same.

Federal Individual Securities Litigation

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

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

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participate in the April 2, 2010 mediation mentioned above in connection with the federal securities class actions. QRCP intends to defend vigorously against the plaintiff s claims.

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

On November 3, 2009, a complaint was filed in the United States District Court for the Western District of Oklahoma naming QRCP, QELP, and certain then current and former officers and directors as defendants. The complaint was filed by individual shareholders of QRCP stock and individual purchasers of QELP common units. The complaint asserts claims under Sections 10(b) and 20(a) of the Exchange Act. The complaint alleges that the defendants violated the federal securities laws by issuing false and misleading statements and/or concealing material information concerning unauthorized transfers from subsidiaries of QRCP to entities controlled by QRCP s former chief executive officer, Mr. Jerry D. Cash. The complaint also alleges that QRCP and QELP issued false and misleading statements and or/concealed material information concerning a misappropriation by its former chief financial officer, Mr. David E. Grose, of $1 million in company funds and receipt of unauthorized kickbacks of approximately $850,000 from a company vendor. The complaint also alleges that, as a result of these actions, the price of QRCP stock and QELP common units was artificially inflated when the plaintiffs purchased QRCP stock and QELP common units. The plaintiffs seek $10 million in damages. QRCP and QELP intend to defend vigorously against the plaintiffs claims. Plaintiffs have agreed to participate in the April 2, 2010 mediation mentioned above in connection with the federal securities class actions.

Federal Derivative Cases

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

On September 25, 2008, a complaint was filed in the United States District Court for the Western District of Oklahoma, purportedly on QRCP s behalf, which named certain of QRCP s then current and former officers and directors as defendants. The factual allegations mirror those in the purported class actions described above, and the complaint asserts claims for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets, and unjust enrichment. The complaint seeks disgorgement, costs, expenses, and equitable and/or injunctive relief. On October 16, 2008, the court stayed this case pending the court s ruling on any motions to dismiss the class action claims. Proceedings in this matter are currently stayed. QRCP intends to defend vigorously against these claims.

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

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

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abetting breaches of fiduciary duties against the individual defendants and vendors and professional negligence and breach of contract against the external auditors. The complaint seeks monetary damages, disgorgement, costs and expenses and equitable and/or injunctive relief. It also seeks QELP to take all necessary actions to reform and improve its corporate governance and internal procedures. On September 8, 2009, the case was transferred to Judge Miles-LaGrange, who is presiding over the other federal cases, and the case number was changed to CIV-09-752-M. All proceedings in this matter are currently stayed under Judge Miles-LaGrange s order of October 16, 2009. QELP intends to defend vigorously against these claims.

State Court Derivative Cases

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

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

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

The factual allegations in these petitions mirror those in the purported class actions discussed above. All three petitions assert claims for breach of fiduciary duty, abuse of control, gross mismanagement, and unjust enrichment. The *Jacobson* petition also asserts claims against the two auditing firms named in that suit for professional negligence and aiding and abetting the director defendants breaches of fiduciary duties. The *Wulfert* petition also asserts a claim against Mr. Bryan Simmons for aiding and abetting Messrs. Cash s and Grose s breaches of fiduciary duties. The petitions seek damages, costs, expenses, and equitable relief. On March 26, 2009, the court consolidated these actions as *In re Quest Resource Corporation Shareholder Derivative Litigation*, Case No. CJ-2008-9042. Under the court s order, the defendants need not respond to the individual petitions. The action is stayed by agreement of the parties until the motions to dismiss in the pending federal securities class action litigation are decided. QRCP intends to defend vigorously against plaintiffs claims.

Royalty Owner Class Action

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

Quest Cherokee, a wholly-owned subsidiary of QELP, was named as a defendant in a class action lawsuit filed by several royalty owners in the U.S. District Court for the District of Kansas. The case was filed by the named plaintiffs on behalf of a putative class consisting of all Quest Cherokee s royalty and overriding royalty owners in the Kansas portion of the Cherokee Basin. Plaintiffs contend that Quest Cherokee failed to properly make royalty payments to them and the putative class by, among other things, paying royalties based on reduced volumes instead of volumes measured at the wellheads, by allocating expenses in excess of the actual costs of the services represented, by allocating production costs to the royalty owners, by improperly allocating marketing costs to the royalty owners, and by making the royalty payments after the statutorily proscribed time for doing so without providing the required interest. Quest Cherokee has answered the complaint and

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denied plaintiffs claims. On July 21, 2009, the court granted plaintiffs motion to compel production of Quest Cherokee s electronically stored information, or ESI, and directed the parties to decide upon a timeframe for producing Quest Cherokee s ESI. Discovery has been stayed until April 14, 2010 to allow the parties to discuss settlement terms.

Litigation Related to Oil and Gas Leases

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

QRCP *et al.* have been named in the above-referenced lawsuit. Plaintiffs are royalty owners who allege that the defendants have wrongfully deducted costs from the royalties of plaintiffs and have engaged in self-dealing contracts resulting in less than market price for the gas production. Plaintiffs pray for unspecified actual and punitive damages. The defendants have filed a motion to dismiss certain tort claims, but no ruling has yet been issued by the Court. Limited pretrial discovery has occurred. No court deadlines have been set. QRCP intends to defend vigorously against the plaintiffs claims.

Environmental Matters As of December 31, 2009 and 2008, 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 We have a leasing agreement for pipeline capacity that includes renewal options and options to increase capacity, which would also increase rentals. The initial term of this lease began June 1, 1992 and ended October 31, 2009. In April 2009, the term of this lease was extended to October 31, 2011.

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

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

Future minimum rental payments under all non-cancelable operating leases as of December 31, 2009, were as follows (in thousands):

Year ending December 31,	
2010	$ 8,929
2011	3,184
2012	1,185
2013	1,128
2014	932
Thereafter	1,783

Total minimum lease obligations	$ 17,141

Total rental expense under operating leases was approximately $17.3 million, $17.2 million and $10.3 million for the years ended December 31, 2009, 2008 and 2007, respectively. Included in 2009 and 2008 are $2.0 million and $3.1 million of expenses for the pipeline capacity lease discussed above, respectively.

Financial Advisor Contracts In October 2008, Quest Midstream GP engaged a financial advisor in connection with the review of QMLP s strategic alternatives. Under the terms of the agreement, the financial

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advisor received an advisory fee of $250,000 in October 2008 and was entitled to additional monthly advisory fees of $75,000 from December 2008 through September 2009. In June 2009, Quest Midstream GP entered into an amendment to this agreement, which provided that in consideration of a one time payment of $1.75 million no additional fees of any kind would be due under the terms of the original agreement other than a fee of $1.5 million if the KPC pipeline is sold within two years of the date of the amendment. During 2009 and 2008, we recorded $1.75 million and $0.3 million, respectively, relating to this agreement in general and administrative expense.

In October 2008, QRCP engaged a financial advisor with respect to a review of its strategic alternatives. Under the terms of the agreement, the financial advisor receives a monthly retention fee of $150,000 per month. In May 2009, QRCP terminated this engagement. This financial advisor is still entitled to fees, which are not currently estimable, if certain transactions occur. In June 2009, QRCP retained a different financial advisor to render a fairness opinion to QRCP in connection with the recombination. During 2009 and 2008, QRCP recorded $0.3 million and $0.3 million, respectively, relating to these agreements in general and administrative expense.

In January 2009, Quest Energy GP engaged a financial advisor to QELP in connection with the review of QELP s strategic alternatives. Under the terms of the agreement, the financial advisor received a one-time advisory fee of $50,000 in January 2009 and was entitled to additional monthly advisory fees of $25,000 for a minimum period of six months payable on the last day of the month beginning January 31, 2009. In addition, the financial advisor was entitled to inestimable fees if certain transactions occur. On July 1, 2009, Quest Energy GP entered into an amendment to its original financial advisor agreement, which provided that the monthly advisory fee increased to $0.2 million per month with a total of $0.8 million, representing the aggregate fees for each of April, May, June and July 2009, which amount was paid upon execution of the amendment. The additional financial advisor fees payable if certain transactions occurred were canceled; however, the financial advisor was still entitled to a fairness opinion fee of $0.7 million in connection with any merger, sale or acquisition involving Quest Energy GP or Quest Energy, which amount was paid in connection with the delivery of a fairness opinion at the time of the execution of the merger agreement related to the recombination.

Note 13 Other Assets

Intangible Assets Balances for the contract-related intangibles acquired in the KPC Pipeline acquisition were as follows as of December 31, 2009 and 2008 (in thousands):

	2009	2008
Gross carrying amount	$ 9,934	$ 9,934
Accumulated amortization	(7,635)	(4,340)
Impairment	(1,035)	
Net carrying amount	$ 1,264	$ 5,594

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

As discussed in Note 5, we recorded an impairment of our KPC pipeline during the fourth quarter of 2009 upon the loss of our 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 QMLP. Upon determining the write-off required for the asset group, we allocated a pro-rata portion of the write-off to the contract related

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

intangibles of $1.0 million. The write-off is reflected as a component of impairments on the consolidated statement of operations.

Deferred Financing Costs The unamortized deferred financing costs at December 31, 2009 and 2008 were $7.0 million and $8.1 million, respectively, and are being amortized over the life of the related credit facilities. Included in the balance as of December 31, 2009 is $0.3 million which is reflected in other assets, net (noncurrrent), while $6.7 million is reflected in other current assets. During 2009, we entered into various amendments to our credit facilities. We evaluated these amendments to determine whether there were substantial modifications to the remaining cash flows of the facilities or whether the borrowing capacity on any of the facilities had been reduced. Depending on circumstances, FASB ASC 470-50-40 requires complete or partial write-offs of unamortized debt issuance costs when the debt amendments substantially modify cash flows or when there is a reduction in borrowing capacity in connection with revolving lines of credit. As a result of our analysis, we recorded a $3.5 million write-off of deferred financing costs in 2009. The Company s expense related to amortizing or writing off deferred financing costs was $7.8 million, $2.1 million and $11.2 million in 2009, 2008 and 2007, respectively. The costs are included in interest expense.

In November 2007, the credit facilities with Guggenheim Corporate Funding, LLC were repaid, resulting in a charge of $9.0 million in unamortized loan fees and $4.1 million in prepayment penalties which are included with interest expense in 2007.

Note 14 Supplemental Cash Flow Information

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash paid for interest	$ 19,293	$ 21,813	$ 32,884
Cash paid for income taxes			
Accrued purchases of property and equipment	415	1,492	861
Accrued distributions QMLP			3,600

Note 15 Related Party Transactions

During the years ended December 31, 2005, 2006 and 2007, our former chief executive officer, Mr. Cash, made certain unauthorized transfers, repayments and re-transfers of funds totaling $2.0 million, $6.0 million and $2.0 million, respectively, to entities that he controlled. The Oklahoma Department of Securities has filed a lawsuit alleging that our former chief financial officer, Mr. David Grose, and our former purchasing manager, Mr. Brent Mueller, stole approximately $1.0 million. In addition to this theft, the Oklahoma Department of Securities has also filed a lawsuit alleging that our former chief financial officer and former purchasing manager received kickbacks totaling approximately $1.8 million ($0.9 million each) from several related suppliers beginning in 2005. In May 2009, the Company entered into a settlement agreement with Mr. Cash and received net assets valued at $3.4 million, as discussed in Note 1.

Note 16 Operating Segments

We divide our operations into two reportable business segments:

- Oil and natural gas production; and
- Natural gas pipelines, including transporting, gathering, treating and processing natural gas.

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). Our reportable segments are strategic business units

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that offer different products and services. Each segment is managed separately because each segment involves different products and marketing strategies. We do not allocate income taxes to our operating segments.

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

	Oil and Natural Gas Production	Natural Gas Pipelines	Other and Intersegment Eliminations	Total
Year Ended December 31, 2009:				
Total revenues	$ 79,893	$ 67,323	$ (41,135)	$ 106,081
Inter-segment revenues		(41,135)	41,135	
Third-party revenues	$ 79,893	$ 26,188	$	$ 106,081
Segment operating profit (loss)	$ (129,788)	$ (143,097)	$	$ (272,885)
Capital expenditures	$ 7,569	$ 1,990	$	$ 9,559
Depreciation, depletion and amortization	$ 32,193	$ 15,609	$	$ 47,802
Impairment	$ 102,902	$ 165,728	$	$ 268,630
Year Ended December 31, 2008:				
Total revenues	$ 162,499	$ 63,722	$ (35,546)	$ 190,675
Inter-segment revenues		(35,546)	35,546	
Third-party revenues	$ 162,499	$ 28,176	$	$ 190,675
Segment operating profit	$ (269,729)	$ 17,245	$	$ (252,484)
Capital expenditures	$ 239,467	$ 27,649	$	$ 267,116
Depreciation, depletion and amortization	$ 53,710	$ 16,735	$	$ 70,445
Impairment	$ 298,861	$	$	$ 298,861
Year Ended December 31, 2007:				
Total revenues	$ 105,285	$ 39,032	$ (29,179)	$ 115,138
Inter-segment revenues		(29,179)	29,179	
Third-party revenues	$ 105,285	$ 9,853	$	$ 115,138
Segment operating profit (loss)	$ 5,999	$ 11,964	$	$ 17,963
Capital expenditures	$ 91,265	$ 173,604	$	$ 264,869
Depreciation, depletion and amortization	$ 33,812	$ 5,970	$	$ 39,782
Identifiable assets:				
December 31, 2009	$ 128,548	$ 155,107	$	$ 283,655
December 31, 2008	$ 311,592	$ 338,584	$	$ 650,176

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Years Ended December 31, 2009	2008	2007
Segment operating profit (loss)(1)	$ (272,885)	$ (252,484)	$ 17,963
General and administrative expenses	(41,723)	(28,269)	(21,023)
Recovery of (loss on) misappropriation of funds	3,412		(2,000)
Gain from derivative financial instruments	48,122	66,145	1,961
Interest expense, net	(29,329)	(25,373)	(43,628)
Other income (expense), net	83	329	(331)
Loss before income taxes and noncontrolling interests	$ (292,320)	$ (239,652)	$ (47,058)

Note 17 Profit Sharing Plan

Substantially all of our employees are covered by our 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. Our match is discretionary; however, prior to 2009, we have matched 100% of total contributions up to a total of five percent of annual compensation. Beginning in 2009, the matched contribution was reduced from five percent to three percent. Prior to July 1, 2009, our matching contribution vests using a graduated vesting schedule over six years of service. Beginning on July 1, 2009, the vesting schedule was reduced to a three year graduated vest. During the years ended December 31, 2009, 2008 and 2007 we made cash contributions to the plan of $0.4 million, $0.6 million and $0.6 million, respectively.

Note 18 Subsequent Events

Recombination

The recombination closed on March 5, 2010. In connection with the closing of the recombination, the following transactions took place:

Quest Resource Acquisition Corp., a wholly owned subsidiary of PostRock, merged with and into QRCP and QRCP common stockholders received 0.0575 shares of PostRock common stock in exchange for each share of QRCP common stock held;

Quest Energy Acquisition, LLC, a wholly owned subsidiary of QRCP, merged with and into QELP (the QELP merger) and QELP common unitholders (other than QRCP) received 0.2859 shares of PostRock common stock in exchange for each QELP common unit held; and

QMLP merged with and into Quest Midstream Acquisition, LLC, a wholly owned subsidiary of QRCP (the QMLP merger), QMLP common unitholders received 0.4033 shares of PostRock common stock in exchange for each QMLP common unit held and the general partner interests in QMLP were converted into shares of PostRock common stock equal to approximately 0.14% of the PostRock common stock issued in the recombination.

Following the QELP merger, QELP, as a wholly owned subsidiary of QRCP, converted into a Delaware limited liability company. In the conversion, the general partner interests in QELP were cancelled for no consideration. Quest Energy GP then merged with and into that limited liability company. In addition, following the QMLP merger, Quest Midstream GP merged with and into the surviving entity of the QMLP merger. In that merger, each holder of Quest Midstream GP units other than QRCP received their pro rata portion of the shares of PostRock common stock receivable by Quest Midstream GP in the QMLP merger described above.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Termination of Certain Intercompany Agreements

Pursuant to the merger agreement, each of the following intercompany agreements was terminated effective as of the closing of the recombination :

Omnibus Agreement among QRCP, QMGP, Bluestem Pipeline, LLC and QMLP, dated December 22, 2006;

Omnibus Agreement among QELP, QEGP and QRCP, dated November 15, 2007; and

Amended and Restated Investors Rights Agreement, dated November 1, 2007, among QMLP, QMGP, QRCP and certain private investors of QMLP party thereto.

Other

We evaluated our activity, through the issuance date, for recognized and unrecognized subsequent events not discussed elsewhere in these footnotes and determined there were none.

Note 19 Supplemental Financial Information Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2009 and 2008 are as follows (in thousands, except per share data):

	Quarters Ended			
	December 31,	**September 30,**	**June 30,**	**March 31,**
2009				
Total revenues	$ 28,348	$ 23,962	$ 23,693	$ 30,078
Impairment(2)	165,728			102,902
Operating income (loss)(1)(4)	(174,491)	(18,416)	(6,617)	(111,672)
Net income (loss)(4)	(166,026)	(16,724)	(30,530)	(79,040)
Net income (loss) per common share:				
Basic	$ (2.01)	$ (0.36)	$ (0.57)	$ (1.62)
Diluted	$ (2.01)	$ (0.36)	$ (0.57)	$ (1.62)

	Quarters Ended			
	December 31,	**September 30,**	**June 30,**	**March 31,**
2008				
Total revenues	$ 32,125	$ 57,043	$ 56,292	$ 45,215
Impairment(3)	298,861			
Operating income (loss)(1)	(317,179)	16,352	12,855	7,219
Net income (loss)	(254,533)	154,356	(97,652)	(41,823)
Net income (loss) per common share:				

Basic	$	(5.43)	$	2.75	$	(2.53)	$	(1.11)
Diluted	$	(5.43)	$	2.75	$	(2.53)	$	(1.11)

(1) Total revenue less total costs and expenses.

(2) The impairment charge of $102.9 million in the first quarter is related to the carrying value of oil and natural gas properties and the impairment charge of $165.7 million in the fourth quarter is related to the carrying value of pipeline assets.

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(3) The impairment charge of $298.9 million in the fourth quarter is related to the carrying value of oil and natural gas properties.

(4) Fourth quarter of 2009 was impacted by the change in prices used in oil and natural gas reserves.

Note 20 Supplemental Information on Oil and Natural Gas Producing Activities (Unaudited)

The supplementary, oil and natural 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 natural gas producing activities, (2) net proved oil and gas reserves, and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves.

Modernization of Oil and Gas Reporting

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC s full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. We adopted these amended rules as of December 31, 2009.

Among the significant changes to reserve disclosures that have resulted from these amendments include:

Pricing mechanism for oil and gas reserves estimation The SEC s previous rules required proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. Price changes could be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

Reasonable certainty The SEC s previous definition of proved oil and gas reserves incorporated certain specific concepts such as lowest known hydrocarbons, which limited the ability to claim proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells.

Because the revised rules generally expand the definition of proved reserves, we had an increase of approximately 1.9 Bcfe of proved reserve estimates as of December 31, 2009.

Unproved reserves The SEC s previous rules prohibited disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and

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possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves and must state whether the reserves are developed or undeveloped. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations.

Net Capitalized Costs

Our aggregate capitalized costs related to oil and natural gas producing activities as of December 31, 2009 and 2008 are summarized as follows (in thousands):

	2009	2008
Oil and natural gas properties and related leasehold costs:		
Proved	$ 205,199	$ 299,629
Unproved	596	10,108
	205,795	309,737
Accumulated depreciation, depletion and amortization	(165,317)	(137,200)
Net capitalized costs	$ 40,478	$ 172,537

Unproved properties not subject to amortization consisted mainly of leaseholds acquired through acquisitions. We will continue to evaluate our unproved properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

Costs Incurred

Costs incurred in oil and natural gas property acquisition, exploration and development activities that have been capitalized for the years ended December 31, 2009, 2008 and 2007 summarized as follows (in thousands):

	2009	2008	2007
Proved property acquisition costs	$ 1,293	$ 152,118(a)	$
Unproved property acquisition costs	705	18,945	15,847
Exploration costs	128	1,273	
Development costs	5,087	58,070	67,586
	$ 7,213	$ 230,406	$ 83,433

(a) Includes the acquisition of the PetroEdge & Seminole County, Oklahoma properties.

Oil and Gas Reserve Quantities

The following reserve schedule was developed by our reserve engineers and sets forth the changes in estimated quantities for our proved reserves, all of which are located in the United States. We retained Cawley, Gillespie & Associates, Inc., independent reserve engineers, to perform the annual year-end independent evaluation of proved reserves.

Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material

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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.

	Gas Mcf	Oil Bbls
Proved reserves:		
Balance, December 31, 2006	198,040,000	32,272
Purchase of reserves in place		
Extensions, discoveries, and other additions	26,368,000	
Sale of reserves		
Revisions of previous estimates(1)	3,490,473	11,354
Production	(16,975,067)	(7,070)
Balance, December 31, 2007	210,923,406	36,556
Purchase of reserves in place	94,727,687	1,560,946
Extensions, discoveries, and other additions	13,897,600	
Sale of reserves	(4,386,200)	
Revisions of previous estimates(2)	(123,204,433)	(833,070)
Production	(21,328,687)	(69,812)
Balance, December 31, 2008	170,629,373	694,620
Purchase of reserves in place	142,985	34,905
Extensions, discoveries, and other additions	62,067	
Sale of reserves		
Revisions of previous estimates	(79,724,789)	177,528
Production	(21,235,065)	(83,015)
Balance, December 31, 2009	69,874,571	824,038
Proved developed reserves		
Balance, December 31, 2007	140,966,295	36,556
Balance, December 31, 2008	136,544,572	682,031
Balance, December 31, 2009	62,135,258	785,345

(1) During 2007, higher prices increased the economic lives of the underlying oil and natural gas properties and thereby increased the estimated future reserves.

(2) Lower prices and projected increases in expected gathering costs at December 31, 2008 as compared to December 31, 2007 reduced the economic lives of the underlying oil and gas properties and thereby decreased the estimated future reserves. Additionally, estimated proved reserves acquired from PetroEdge in 2008

decreased approximately 35.5 Bcfe due to the decrease in natural gas prices between the dated of the PetroEdge acquisition and December 31, 2008 and approximately 43.2 Bcfe, as a result of further technical analysis of the estimated PetroEdge reserves.

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Standardized Measure of Discounted Future Net Cash Flows

The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2009, 2008 and 2007 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 our proved oil and gas reserves (in thousands).

	2009	2008	2007
Future cash inflows	$ 311,831	$ 898,214	$ 1,351,980
Future production costs	202,645	570,142	732,488
Future development costs	17,398	60,318	119,448
Future income tax expense			56,371
Future net cash flows	91,788	267,754	443,673
10% annual discount for estimated timing of cash flows	41,229	103,660	157,496
Standardized measure of discounted future net cash flows related to proved reserves	$ 50,559	$ 164,094	$ 286,177

Future cash inflows are computed by applying year-end prices (for 2007 and 2008) or a twelve-month average price (for 2009), 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	2008	2007
Crude oil price per Bbl	$ 61.18	$ 44.60	$ 92.01
Natural gas price per Mmbtu	$ 3.87	$ 5.71	$ 6.43

The principal changes in the standardized measure of discounted future net cash flows relating to proven oil and natural gas properties were as follows (in thousands):

	As of December 31,		
	2009	2008	2007
Present value, beginning of period	$ 164,094	$ 286,177	$ 230,832

Net changes in prices and production costs	(35,203)	(122,702)	13,716
Net changes in future development costs	20,727	(4,247)	(43,530)
Previously estimated development costs incurred	5,292	66,060	74,310
Sales of oil and gas produced, net	(46,442)	(103,826)	(68,990)
Extensions and discoveries	50	15,986	49,901
Purchases of reserves in-place	283	119,733	
Sales of reserves in-place		(5,045)	
Revisions of previous quantity estimates	(63,230)	(147,464)	6,735
Net change in income taxes		36,360	880
Accretion of discount	17,576	31,804	25,264
Timing differences and other(a)	(12,588)	(8,742)	(2,941)
Present value, end of period	$ 50,559	$ 164,094	$ 286,177

(a) The change in timing differences and other are related to revisions in our estimated time of production and development.

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 19th day of March, 2010.

POSTROCK ENERGY CORPORATION

/s/ David C. Lawler
David C. Lawler
Chief Executive Officer and President

POWER OF ATTORNEY

By signing this Annual Report on Form 10-K below, I hereby appoint each of David C. Lawler and Eddie M. LeBlanc, III, as my attorney-in-fact to sign any and all amendments to this Annual Report on Form 10-K on my behalf, and to file this Annual Report on Form 10-K (including all exhibits and other documents related to the Annual Report on Form 10-K) with the Securities and Exchange Commission. I authorize each of my attorneys-in-fact to (1) appoint a substitute attorney-in-fact for himself and (2) perform any actions that he believes are necessary or appropriate to carry out the intention and purpose of this Power of Attorney. I ratify and confirm all lawful actions taken directly or indirectly by my attorneys-in-fact and by any properly appointed substitute attorneys-in-fact.

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

Name	Capacity	Date
/s/ David C. Lawler David C. Lawler	Chief Executive Officer and President and Director (Principal Executive Officer)	March 19, 2010
/s/ Eddie M. LeBlanc, III Eddie M. LeBlanc, III	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	March 19, 2010
/s/ Gary M. Pittman Gary M. Pittman	Chairman of the Board	March 19, 2010
/s/ William H. Damon III William H. Damon III	Director	March 19, 2010
/s/ Gabriel Hammond Gabriel Hammond	Director	March 19, 2010

/s/ Duke R. Ligon	Director	March 19, 2010
Duke R. Ligon		
/s/ J. Philip McCormick	Director	March 19, 2010
J. Philip McCormick		
/s/ John H. Rateau	Director	March 19, 2010
John H. Rateau		
/s/ Daniel Spears	Director	March 19, 2010
Daniel Spears		
/s/ Mark A. Stansberry	Director	March 19, 2010
Mark A. Stansberry		

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).
3.1*	Restated Certificate of Incorporation of PostRock (incorporated herein by reference to Exhibit 3.1 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
3.2*	Bylaws of PostRock (incorporated herein by reference to Exhibit 3.2 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
4.1*	Specimen of certificate for shares of Common Stock of PostRock (incorporated herein by reference to Exhibit 4.1 to Amendment No. 1 to PostRock s Registration Statement on Form S-4 filed on December 17, 2009, Registration No. 333-162366 (the Form S-4).
10.1*	Registration Rights Agreement dated March 5, 2010, between PostRock Energy Corporation, 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).
10.2*	Form of Quest Resource Corporation s Indemnification Agreement for Directors (incorporated herein by reference to Exhibit 10.10 to QRCP s Annual Report on Form 10-K filed on June 3, 2009).
10.3*	Form of Quest Resource Corporation s Indemnification Agreement for Officers (incorporated herein by reference to Exhibit 10.11 to QRCP s Annual Report on Form 10-K filed on June 3, 2009).
10.4*	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).
10.5*	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).
10.6*	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).
10.7*	Assignment and Amendment Agreement dated March 5, 2010, between PostRock Energy Corporation, Quest Resource Corporation 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).
10.8*	Employment Agreement dated December 3, 2007 between QRCP and Jack T. Collins (incorporated herein by reference to Exhibit 10.28 to QRCP s Annual Report on Form 10-K filed on March 10, 2008).

10.9*	First Amendment to Employment Agreement, dated October 23, 2008, between QRCP and Jack Collins (incorporated herein by reference to Exhibit 10.3 to QRCP s Current Report on Form 8-K filed on October 24, 2008).
10.10*	Second Amendment to Employment Agreement, dated August 28, 2009, between QRCP and Jack Collins (incorporated herein by reference to Exhibit 10.5 to QRCP s Quarterly Report on Form 10-Q filed on November 5, 2009).

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Exhibit No.	Description
10.11*	Assignment and Amendment Agreement dated March 5, 2010, between PostRock Energy Corporation, Quest Resource Corporation and Jack Collins (incorporated herein by reference to Exhibit 10.13 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.12*	Nonqualified Stock Option Agreement, dated October 23, 2008, between QRCP and Jack Collins (incorporated herein by reference to Exhibit 10.5 to QRCP s Current Report on Form 8-K filed on October 24, 2008).
10.13*	Employment Agreement dated March 21, 2007 between QRCP and Richard Marlin (incorporated herein by reference to Exhibit 10.30 to QRCP s Annual Report on Form 10-K filed on March 10, 2008).
10.14*	First Amendment to Employment Agreement, dated December 29, 2008, between QRCP and Richard Marlin (incorporated herein by reference to Exhibit 10.32 to QRCP s Annual Report on Form 10-K filed on June 3, 2009).
10.15*	Assignment and Amendment Agreement dated March 5, 2010, between PostRock Energy Corporation, Quest Resource Corporation and Richard Marlin (incorporated herein by reference to Exhibit 10.14 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.16*	Employment Agreement, dated December 7, 2009, between QRCP and Eddie LeBlanc (incorporated herein by reference to Exhibit 10.2 to QRCP s Current Report on Form 8-K filed on December 11, 2009).
10.17*	Assignment and Amendment Agreement dated March 5, 2010, between PostRock Energy Corporation, Quest Resource Corporation and Eddie M. LeBlanc, III (incorporated herein by reference to Exhibit 10.12 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.18*	Nonqualified Stock Option Agreement, dated January 12, 2009, between QRCP and Eddie LeBlanc (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on January 14, 2009).
10.19*	Office Lease dated May 31, 2007 between QRCP and Oklahoma Tower Realty Investors, L.L.C. (incorporated herein by reference to Exhibit 10.5 to QRCP s Quarterly Report on Form 10-Q filed on August 9, 2007).
10.20*	Assignment and Assumptions of Leases, dated as of February 28, 2008, by and between Chesapeake Energy Corporation and QRCP (incorporated herein by reference to Exhibit 10.7 to QRCP s Quarterly Report on Form 10-Q filed on May 12, 2008).
10.21*	Amended and Restated Credit Agreement, dated as of November 1, 2007, by and among Quest Midstream Partners, L.P., Bluestem Pipeline, LLC, Royal Bank of Canada, RBC Capital Markets and the Lenders party thereto (incorporated herein by reference to Exhibit 10.5 to QRCP s Current Report on Form 8-K filed on November 2, 2007).
10.22*	First Amendment to the Amended and Restated Credit Agreement, dated as of November 1, 2007 among Quest Midstream Partners, L.P., Bluestem Pipeline, LLC, Royal Bank of Canada and certain guarantors (incorporated herein by reference to Exhibit 10.29 to QRCP s Registration Statement on Form S-4 filed on February 7, 2008).
10.23*	Second Amendment to Amended and Restated Credit Agreement, dated as of October 28, 2008, but effective as of November 5, 2008, by and among Quest Midstream Partners, L.P., Bluestem Pipeline, LLC, Quest Kansas General Partner, L.L.C., Quest Kansas Pipeline, L.L.C., Quest Pipeline (KPC), Royal Bank of Canada and the Lenders party thereto (incorporated herein by reference to Exhibit 10.4 to QRCP s Current Report on Form 8-K filed on November 7, 2008).
10.24*	Third Amendment to Amended and Restated Credit Agreement, dated as of December 17, 2009, by and among Quest Midstream Partners, L.P., Bluestem Pipeline, LLC, Quest Kansas General Partner, L.L.C., Quest Kansas Pipeline, L.L.C., Quest Pipeline (KPC), Royal Bank of Canada and the Lenders party

	thereto (incorporated by reference to Exhibit 10.17 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009).
10.25*	Guaranty by Quest Kansas General Partner, L.L.C., Quest Kansas Pipeline, L.L.C., and Quest Pipeline (KPC) in favor of Royal Bank of Canada, dated as of November 1, 2007 (incorporated herein by reference to Exhibit 10.9 to QRCP s Quarterly Report on Form 10-Q filed on November 9, 2007).

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Exhibit No.	Description
10.26*	Guaranty by Quest Transmission Company, LLC in favor of Royal Bank of Canada, dated as of February, 21, 2008 (incorporated herein by reference to Exhibit 10.41 to QRCP s Annual Report on Form 10-K filed on June 3, 2009).
10.27*	Guaranty dated March 5, 2010, by PostRock Energy Corporation and PostRock Energy Services Corporation (formerly known as Quest Resource Corporation) for the benefit of Royal Bank of Canada. (incorporated herein by reference to Exhibit 10.10 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.28*	Pledge and Security Agreement by Quest Transmission Company, LLC in favor of Royal Bank of Canada, dated as of February 21, 2008 (incorporated herein by reference to Exhibit 10.42 to QRCP s Annual Report on Form 10-K filed on June 3, 2009).
10.29*	Pledge and Security Agreement by Quest Kansas General Partner, L.L.C. in favor of Royal Bank of Canada, dated as of November 1, 2007 (incorporated herein by reference to Exhibit 10.10 to QRCP s Quarterly Report on Form 10-Q filed on November 9, 2007).
10.30*	Pledge and Security Agreement by Quest Kansas Pipeline, L.L.C. in favor of Royal Bank of Canada, dated as of November 1, 2007 (incorporated herein by reference to Exhibit 10.11 to QRCP s Report on Form 10-Q filed on November 9, 2007).
10.31*	Pledge and Security Agreement by Quest Pipelines (KPC) in favor of Royal Bank of Canada, dated as of November 1, 2007 (incorporated herein by reference to Exhibit 10.12 to QRCP s Quarterly Report on Form 10-Q filed on November 9, 2007).
10.32*	Amended and Restated Pledge and Security Agreement by Bluestem Pipeline, LLC in favor of Royal Bank of Canada, dated as of November 1, 2007 (incorporated herein by reference to Exhibit 10.13 to QRCP s Quarterly Report on Form 10-Q filed on November 9, 2007).
10.33*	Amended and Restated Pledge and Security Agreement by Quest Midstream Partners, L.P. in favor of Royal Bank of Canada, dated as of November 1, 2007 (incorporated herein by reference to Exhibit 10.14 to QRCP s Quarterly Report on Form 10-Q filed on November 9, 2007).
10.34*	First Amendment to Amended and Restated Pledge and Security Agreement by Quest Midstream Partners, L.P. in favor of Royal Bank of Canada, dated as of February 21, 2008 (incorporated herein by reference to Exhibit 10.48 to QRCP s Annual Report on Form 10-K filed on June 3, 2009).
10.35*	Pledge and Security Agreement dated March 5, 2010, by PostRock Energy Services Corporation (formerly known as Quest Resource Corporation) for the benefit of Royal Bank of Canada (incorporated herein by reference to Exhibit 10.9 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.36*	Amended and Restated Credit Agreement, dated as of November 15, 2007, by and among QRCP , as the Initial Co-Borrower, Quest Cherokee, LLC, as the Borrower, Quest Energy Partners, L.P., as a Guarantor, Royal Bank of Canada, as Administration Agent and Collateral Agent, KeyBank National Association, as Documentation Agent, and the lenders from time to time party thereto (incorporated herein by reference to Exhibit 10.3 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.37*	First Amendment to Amended and Restated Credit Agreement, dated as of April 15, 2008, by and among Quest Cherokee, LLC, Royal Bank of Canada, KeyBank National Association, and the lenders Party Thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on April 23, 2008).
10.38*	Second Amendment to Amended and Restated Credit Agreement, dated as of October 28, 2008, but effective as of November 5, 2008, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association and the

	Lenders party thereto (incorporated herein by reference to Exhibit 10.3 to QRCP s Current Report on Form 8-K filed on November 7, 2008).
10.39*	Third Amendment to Amended and Restated Credit Agreement, dated as of May 29, 2009, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on June 23, 2009).

Exhibit No.	Description
10.40*	Fourth Amendment to Amended and Restated Credit Agreement, dated as of June 30, 2009, among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association and the Required Lenders party thereto (incorporated herein by reference to Exhibit 10.5 to QRCP s Current Report on Form 8-K filed on July 7, 2009).
10.41*	Fifth Amendment to Amended and Restated Credit Agreement, dated as of December 17, 2009, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, STP Newco, Inc., Royal Bank of Canada, KeyBank National Association and the Lenders party thereto (incorporated by reference to Exhibit 10.32 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009).
10.42*	Second Amended and Restated Credit Agreement, dated as of September 11, 2009, by and among QRCP, as the Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent, and the lenders from time to time party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on September 17, 2009).
10.43*	First Amendment to Second Amended and Restated Credit Agreement, dated as of November 30, 2009, by and among QRCP, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and as the Lender, and the Guarantors party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on December 1, 2009).
10.44*	Second Amendment to Second Amended and Restated Credit Agreement, dated as of December 17, 2009, by and among QRCP, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and as the Lender, and the Guarantors party thereto (incorporated by reference to Exhibit 10.35 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009).
10.45*	Loan Transfer Agreement, dated as of November 15, 2007, by and among QRCP, Quest Cherokee, LLC, Quest Oil & Gas, LLC, Quest Energy Service, Inc., Quest Cherokee Oilfield Service, LLC, Guggenheim Corporate Funding, LLC, Wells Fargo Foothill, Inc., and Royal Bank of Canada (incorporated herein by reference to Exhibit 10.6 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.46*	Guaranty for Credit Agreement by Quest Oil & Gas, LLC and Quest Energy Service, LLC in favor of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.7 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.47*	Pledge and Security Agreement for Credit Agreement by Quest Energy Service, LLC for the benefit of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.8 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.48*	Pledge and Security Agreement for Credit Agreement by Quest Oil & Gas, LLC for the benefit of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.9 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.49*	First Amendment to Pledge and Security Agreement for Amended and Restated Credit Agreement by Quest Oil & Gas, LLC for the benefit of Royal Bank of Canada, dated May 29, 2009 (incorporated herein by reference to Exhibit 10.67 to QRCP s Annual Report on Form 10-K filed on June 3, 2009).
10.50*	Pledge and Security Agreement for Credit Agreement by Quest Resource Corporation for the benefit of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.10 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.51*	First Amendment to Pledge and Security Agreement for Amended and Restated Credit Agreement by QRCP for the benefit of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.4 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.52*	

	Second Amendment to Pledge and Security Agreement dated March 5, 2010, by PostRock Energy Services Corporation (formerly known as Quest Resource Corporation) for the benefit of Royal Bank of Canada (incorporated herein by reference to Exhibit 10.2 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.53*	Release Agreement dated March 5, 2010, by Royal Bank of Canada in favor of Quest Resource Corporation (incorporated herein by reference to Exhibit 10.3 to PostRock s Current Report on Form 8-K filed on March 10, 2010).

Exhibit No.	Description
10.54*	Release Agreement dated March 5, 2010, by Royal Bank of Canada in favor of Quest Resource Corporation (incorporated herein by reference to Exhibit 10.4 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.55*	First Lien Senior Pledge and Security Agreement dated March 5, 2010, by PostRock Energy Services Corporation (formerly known as Quest Resource Corporation) for the benefit of Royal Bank of Canada (incorporated herein by reference to Exhibit 10.5 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.56*	Guaranty dated March 5, 2010, by PostRock Energy Corporation and PostRock Energy Services Corporation (formerly known as Quest Resource Corporation) for the benefit of Royal Bank of Canada (incorporated herein by reference to Exhibit 10.6 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.57*	Guaranty for Amended and Restated Credit Agreement by Quest Energy Partners, L.P. in favor of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.11 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.58*	Guaranty for Amended and Restated Credit Agreement by Quest Cherokee Oilfield Service, LLC in favor of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.12 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.59*	Guaranty for Amended and Restated Credit Agreement by STP Newco, Inc. in favor of Royal Bank of Canada, dated as of July 16, 2009, but effective as of May 29, 2009 (incorporated herein by reference to Exhibit 10.45 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009).
10.60*	Pledge and Security Agreement for Amended and Restated Credit Agreement by Quest Energy Partners, L.P. for the benefit of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.13 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.61*	First Amendment to Pledge and Security Agreement for Amended and Restated Credit Agreement by Quest Energy Partners, L.P. for the benefit of Royal Bank of Canada, dated as of July 16, 2009, but effective as of May 29, 2009 (incorporated herein by reference to Exhibit 10.47 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009).
10.62*	Pledge and Security Agreement for Amended and Restated Credit Agreement by Quest Cherokee Oilfield Service, LLC for the benefit of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.14 to QRCP s Current Report on Form 8-K filed on November 21, 2007).
10.63*	Pledge and Security Agreement for Amended and Restated Credit Agreement by Quest Cherokee, LLC for the benefit of Royal Bank of Canada, dated as of November 15, 2007 (incorporated herein by reference to Exhibit 10.15 to Quest Resource Corporation s Current Report on Form 8-K filed on November 21, 2007).
10.64*	Pledge and Security Agreement for Amended and Restated Credit Agreement by STP Newco, Inc. for the benefit of Royal Bank of Canada, dated as of July 16, 2009, but effective as of May 29, 2009. (incorporated herein by reference to Exhibit 10.50 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009).
10.65*	Pledge and Security Agreement for Amended and Restated Credit Agreement by Quest Eastern Resource LLC for the benefit of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.2 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.66*	Pledge and Security Agreement for Amended and Restated Credit Agreement, dated as of July 11, 2008, by Quest Mergersub, Inc., for the benefit of Royal Bank of Canada (incorporated herein by

	reference to Exhibit 10.3 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.67*	Guaranty for Amended and Restated Credit Agreement by Quest Eastern Resource LLC in favor of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.5 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.68*	Guaranty for Amended and Restated Credit Agreement by Quest Mergersub, Inc. in favor of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.6 to QRCP s Current Report on Form 8-K filed on July 16, 2008).

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Exhibit No.	Description
10.69*	Second Lien Senior Term Loan Agreement, dated as of July 11, 2008, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Royal Bank of Canada, KeyBank National Association, Société Générale, the lenders party thereto and RBC Capital Markets (incorporated herein by reference to Exhibit 10.7 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.70*	First Amendment to Second Lien Senior Term Loan Agreement, dated as of October 28, 2008, but effective as of November 5, 2008, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, Keybank National Association, Société Générale and the Lenders party thereto (incorporated herein by reference to Exhibit 10.2 to QRCP s Current Report on Form 8-K filed on November 7, 2008).
10.71*	Second Amendment to Second Lien Senior Term Loan Agreement, dated as of June 30, 2009, among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association, Société Générale and the Required Lenders party thereto (incorporated herein by reference to Exhibit 10.6 to QRCP s Current Report on Form 8-K filed on July 7, 2009).
10.72*	Third Amendment to Second Lien Senior Term Loan Agreement, dated as of September 30, 2009, among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association, Société Générale and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on October 1, 2009).
10.73*	Fourth Amendment to Second Lien Senior Term Loan Agreement, dated as of October 31, 2009, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association, Société Générale and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on November 2, 2009).
10.74*	Fifth Amendment to Second Lien Senior Term Loan Agreement, dated as of November 16, 2009, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association, Société Générale and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on November 20, 2009).
10.75*	Sixth Amendment to Second Lien Senior Term Loan Agreement, dated as of November 20, 2009, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association, Société Générale and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on November 25, 2009).
10.76*	Seventh Amendment to Second Lien Loan Agreement, dated as of December 7, 2009, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association, Société Générale and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on December 11, 2009).
10.77*	Eighth Amendment to Second Lien Senior Term Loan Agreement, dated as of December 17, 2009, by and among Quest Cherokee, LLC, Quest Energy Partners, L.P., Quest Cherokee Oilfield Service, LLC, Royal Bank of Canada, KeyBank National Association, Société Générale and the Lenders party thereto (incorporated herein by reference to Exhibit 10.63 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009).
10.78*	

	Guaranty for Second Lien Term Loan Agreement by Quest Cherokee Oilfield Service, LLC in favor of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.8 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.79*	Guaranty for Second Lien Term Loan Agreement by Quest Energy Partners, L.P. in favor of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.9 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.80*	Guaranty dated March 5, 2010, by PostRock Energy Corporation and PostRock Energy Services Corporation (formerly known as Quest Resource Corporation) for the benefit of Royal Bank of Canada (incorporated herein by reference to Exhibit 10.8 to PostRock s Current Report on Form 8-K filed on March 10, 2010).

Exhibit No.	Description
10.81*	Second Lien Senior Pledge and Security Agreement dated March 5, 2010, by PostRock Energy Services Corporation (formerly known as Quest Resource Corporation) for the benefit of Royal Bank of Canada (incorporated herein by reference to Exhibit 10.7 to PostRock s Current Report on Form 8-K filed on March 10, 2010).
10.82*	Second Lien Senior Pledge and Security Agreement for the Second Lien Senior Term Loan Agreement by Quest Cherokee Oilfield Service, LLC for the benefit of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.10 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.83*	Second Lien Senior Pledge and Security Agreement for the Second Lien Senior Term Loan Agreement by Quest Energy Partners, L.P. for the benefit of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.11 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.84*	Second Lien Senior Pledge and Security Agreement for the Second Lien Senior Term Loan Agreement by Quest Cherokee, LLC for the benefit of Royal Bank of Canada, dated as of July 11, 2008 (incorporated herein by reference to Exhibit 10.12 to QRCP s Current Report on Form 8-K filed on July 16, 2008).
10.85*	Amended and Restated Intercreditor Agreement and Collateral Agency Agreement, dated as of June 18, 2009, by and among Royal Bank of Canada, BP Corporation North America, Inc. and Quest Cherokee, LLC (incorporated herein by reference to Exhibit 10.2 to QRCP s Current Report on Form 8-K filed on June 23, 2009).
10.86*	First Amendment to Office Lease, dated as of February 7, 2008, by and between Cullen Allen Holdings L.P. and Quest Midstream Partners, L.P. (incorporated herein by reference to Exhibit 10.6 to QRCP s Quarterly Report on Form 10-Q filed on May 12, 2008).
10.87*	Support Agreement, dated as of July 2, 2009, among Quest Resource Corporation, Quest Midstream Partners, L.P., Quest Energy Partners, L.P. and each of the unitholders of Quest Midstream Partners, L.P. party thereto (incorporated herein by reference to Exhibit 10.1 to QRCP s Current Report on Form 8-K filed on July 7, 2009).
10.88*	First Amendment dated as of October 2, 2009 to the Support Agreement, dated as of July 2, 2009, among QRCP, Quest Midstream Partners, L.P., Quest Energy Partners, L.P. and each of the unitholders of Quest Midstream Partners, L.P. party thereto (incorporated herein by reference to Exhibit 10.61 to PostRock s Registration Statement on Form S-4 filed on October 6, 2009).
10.89*	PostRock Energy Corporation 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).
10.90*	Form of QRCP s 2005 Stock Award Plan Nonqualified Stock Option Agreement (incorporated herein by reference to Exhibit 10.8 to QRCP s Registration Statement on Form S-1 filed on December 12, 2005).
10.91*	Nonqualified Stock Option Agreement, dated August 15, 2007, between QRCP and William Damon III (incorporated herein by reference to Exhibit 10.75 to PostRock s Registration Statement on Form S-4/A filed on December 17, 2009).
10.92*	Form of QRCP s Bonus Share Award Agreement for senior staff (incorporated herein by reference to Exhibit 10.3 to QRCP s Current Report on Form 8-K filed on December 11, 2009).
10.93*	Form of QRCP s Bonus Share Award Agreement for non-senior staff (incorporated herein by reference to Exhibit 10.4 to QRCP s Current Report on Form 8-K filed on December 11, 2009).
10.94*	Form of Quest Energy Partners, L.P. s Phantom Unit Award Agreement for senior staff (incorporated herein by reference to Exhibit 10.2 to QELP s Current Report on Form 8-K filed on December 11,

	2009).
10.95*	Form of Quest Energy Partners, L.P. s Phantom Unit Award Agreement for non-senior staff (incorporated herein by reference to Exhibit 10.3 to QELP s Current Report on Form 8-K filed on December 11, 2009).
10.96*	Form of Quest Midstream Partners, L.P. s Restricted Unit Award Agreement for senior staff (incorporated herein by reference to Exhibit 10.7 to QRCP s Current Report on Form 8-K filed on December 11, 2009).

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Exhibit No.	Description
10.97*	Form of Quest Midstream Partners, L.P. s Restricted Unit Award Agreement for non-senior staff (incorporated herein by reference to Exhibit 10.8 to QRCP s Current Report on Form 8-K filed on December 11, 2009).
21.1	List of Subsidiaries.
23.1	Consent of Cawley, Gillespie & Associates, Inc.
23.2	Consent of UHY, LLP.
31.1	Certification by principal executive officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification by principal financial officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification by principal executive officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification by principal financial officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of Cawley, Gillespie & Associates, Inc.

* Incorporated by reference.

Management contracts and compensatory plans and arrangements required to be filed as Exhibits pursuant to Item 14(a) of this report.

PLEASE NOTE: Pursuant to the rules and regulations of the Securities and Exchange Commission, we have filed or incorporated by reference the agreements referenced above as exhibits to this Annual Report on Form 10-K. The agreements have been filed to provide investors with information regarding their respective terms. The agreements are not intended to provide any other factual information about PostRock or its business or operations. In particular, the assertions embodied in any representations, warranties and covenants contained in the agreements may be subject to qualifications with respect to knowledge and materiality different from those applicable to investors and may be qualified by information in confidential disclosure schedules not included with the exhibits. These disclosure schedules may contain information that modifies, qualifies and creates exceptions to the representations, warranties and covenants set forth in the agreements. Moreover, certain representations, warranties and covenants in the agreements may have been used for the purpose of allocating risk between the parties, rather than establishing matters as facts. In addition, information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the respective agreement, which subsequent information may or may not be fully reflected in our public disclosures. Accordingly, investors should not rely on the representations, warranties and covenants in the agreements as characterizations of the actual state of facts about PostRock or its business or operations on the date hereof.