ENERGY PARTNERS LTD
Form 10-K
March 11, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

or

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

For the transition period from to

Commission file number: 001-16179

Energy Partners, Ltd.

(Exact name of registrant as specified in its charter)

Delaware	**72-1409562**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
201 St. Charles Avenue, Suite 3400	
New Orleans, Louisiana	**70170**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code:

504-569-1875

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of exchange on which registered**
Common Stock, Par Value $0.001 Per Share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

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

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

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 x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 ¨ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the 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. x

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.

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

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

The aggregate market value of the common stock held by non-affiliates of the registrant at June 30, 2009 (the registrant s most recently completed second fiscal quarter) based on the closing stock price as quoted on the Pink Sheets on that date was $9,981,297. As of March 8, 2010, there were 40,041,334 shares of the registrant s common stock, par value $0.001 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the Annual Meeting of Stockholders of Energy Partners, Ltd. to be held on May 20, 2010

(to be filed with the Securities and Exchange Commission prior to May 1, 2010).

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Statements we make in this Annual Report on Form 10-K (Annual Report) which express a belief, expectation or intention, as well as those that are not historical fact, may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Our forward-looking statements are subject to various risks, uncertainties and assumptions, including those to which we refer under the headings Cautionary Statement Concerning Forward-Looking Statements and Risk Factors in Items 1 and 1A of Part 1 of this Annual Report.

PART I

Item 1. *Business*

Overview

Energy Partners, Ltd. (referred to herein as we, our, us or the Company) was incorporated as a Delaware corporation in January 1998 and operates as an independent oil and natural gas exploration and production company. Our current operations are concentrated in the shallow to moderate-depth waters in the Gulf of Mexico focusing on the areas offshore Louisiana as well as the deepwater Gulf of Mexico at depths less than 5,000 feet.

Our management professionals and geoscientists have considerable geological, geophysical, technical and operational experience that is specific to the Gulf of Mexico and Gulf Coast region. Since inception, we have expanded our technical knowledge base through the addition of geophysical and geological data relating to these areas. We believe that these regions offer a balanced and expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations. As of December 31, 2009, we had estimated proved reserves of approximately 19.9 million barrels (Mmbbls) of oil and 67.4 billion cubic feet (Bcf) of natural gas, or an aggregate of approximately 31.2 million barrels of oil equivalent (Mmboe), with a standardized measure of discounted future net cash flows of $393.8 million (see Oil and Natural Gas Reserves for more information about standardized measure of discounted future net cash flows).

We produce both oil and natural gas. Throughout this Annual Report, when we refer to total production, total reserves, percentage of production, percentage of reserves, or any similar term, we have converted our natural gas reserves or production into barrel equivalents. For this purpose, six thousand cubic feet of natural gas is equal to one barrel of oil, which is based on the relative energy content of natural gas and oil. Natural gas liquids are aggregated with oil in this Annual Report.

For definitions of oil and natural gas terms used frequently in this Annual Report, please refer to the Glossary of Oil and Natural Gas Terms following the index of Exhibits in Item 15 of Part IV of this Annual Report.

Recent Events

Reorganization under Chapter 11 and Emergence from Bankruptcy

Our reorganization in bankruptcy in 2009 (described below) substantially reduced our indebtedness and restructured our balance sheet. Throughout the course of our Chapter 11 reorganization, we continued to operate in the ordinary course of business without the sale of any assets and continued to meet our business obligations to our vendors and joint interest owners. As a result of our Chapter 11 reorganization, the Company now has an improved capital structure and enhanced financial flexibility.

On May 1, 2009, we and certain of our subsidiaries filed voluntary petitions (In re: Energy Partners, Ltd., et. al., Case No. 09-32957) for reorganization under Chapter 11 of Title 11 of the United States Code, 11 U.S.C. §§ 101 et seq., as amended (Chapter 11), in the United States Bankruptcy Court for the Southern District of

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Texas, Houston Division (the Bankruptcy Court). On September 17, 2009, the Bankruptcy Court entered an order confirming the plan of reorganization we had filed with the Bankruptcy Court (the Plan). On September 21, 2009 (the Exit Date), we emerged from Chapter 11 reorganization pursuant to the Plan. Our Chapter 11 reorganization and related matters are addressed in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, and in Note 3, Reorganization and Fresh-Start Accounting to our consolidated financial statements contained in Item 8, Financial Statements and Supplementary Data.

Shortly following our emergence from Chapter 11 reorganization, we provided the Minerals Management Service (the MMS) with surety bonds in support of decommissioning obligations on certain federal leases in the Gulf of Mexico, and production previously shut in from the Company s federal leases in the East Bay field pursuant to a March 2009 MMS order recommenced from those leases. We believe that our improved financial condition may result in our qualifying for a financial waiver of MMS supplemental bonding requirements in 2010, which would result in reductions in our surety bond costs and a release of related surety bond collateral.

Our Board of Directors and Chief Executive Officer

We emerged from our Chapter 11 reorganization with a five-member board of directors (the Board) whose members were appointed by operation of the Plan with the approval of the Bankruptcy Court. The members of our Board have significant experience in the oil and gas exploration and production sector as well as the financial industry. Members of the Board have complementary skills in exploration and production leadership, exploration, financial and operating risk management as well as investment banking.

On the Exit Date, the Board appointed a new chief executive officer to lead our executive management team. Our new chief executive officer, Gary C. Hanna, has nearly 30 years of experience as an executive in the oil and gas exploration and production sector. We believe the Board s experience complements our new chief executive officer and management team with regard to the development and execution of our new business strategy.

Cost Reduction Efforts

During 2009, including the period following our emergence from Chapter 11 reorganization, we undertook meaningful cost reductions in general and administrative (G&A) expenses and lease operating expenses (LOE). These cost reductions included significant reductions in both our workforce and office space in our New Orleans and Houston offices, reductions in the use of third party contractors and consultants, lower marine transportation and liftboat costs and lower corporate governance costs. We have established cost leadership as a corporate goal.

Post-Reorganization Strategy

Capital Structure

On the Exit Date, we consummated certain transactions contemplated by the Plan, including entering into a senior secured credit facility consisting of a $125 million revolving credit facility with an initial borrowing base of $45 million (the Revolver) and a $25 million one-year amortizing term loan facility (together with the Revolver, the Credit Facility). On the Exit Date, we drew $25 million under the Revolver. We also issued 20% Senior Subordinated Secured PIK Notes due 2014 in an aggregate original principal amount of $61.1 million (the PIK Notes). The PIK Notes were issued with original issue discount, and the note proceeds after this discount were $55 million. As of December 31, 2009, we had $26.7 million of cash and cash equivalents on our balance sheet, had fully repaid the Revolver and had $18.8 million of outstanding borrowings under the term loan portion of the Credit Facility. As of the date of this Annual Report, the cash and cash equivalents on our balance sheet has increased, our Revolver remained undrawn and we are continuing to reduce the amounts outstanding under the Credit Facility as we amortize the term loan portion thereof.

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A key focus of management in 2010 is seeking to reduce our cost of financing. Among other things, management will seek to refinance the PIK Notes and/or the Credit Facility in order to achieve this objective.

Near Term Strategy

Following our Chapter 11 reorganization, we have entered 2010 with a continuing focus on achieving meaningful cost reductions in G&A expenses and LOE, converting non-producing reserves to cash flow, developing a core competency in plugging, abandonment and decommissioning operations and evaluating opportunities while allocating capital in a rigorous and disciplined manner intended to achieve an overall lower risk capital expenditure profile. Our process for allocating capital focuses on maximizing rate of return and requires projects to compete on that basis.

For 2010, we have an initial authorized capital budget of approximately $57 million, of which approximately $45 million is allocated for exploration and development expenditures and $12 million for plugging, abandonment and other decommissioning expenditures. This initial capital budget is focused on maximizing the return from existing development opportunities and converting nonproducing reserves, primarily oil reserves, to production and positive cash flow. Our near term goal through these efforts is to stabilize existing production levels that are subject to natural reservoir declines. These activities are more heavily weighted toward the first half of the year. As the year progresses, and as we evaluate the initial results of our capital expenditure program, our budget may be increased to fund additional development or exploration opportunities to the extent we have cash available in excess of that contemplated by the initial capital budget.

Our initial capital expenditure budget is focused primarily on pursuing development opportunities in our existing Gulf of Mexico shelf portfolio and does not include any acquisitions, for which we do not budget, or deepwater activities. Capital expenditures on our Deepwater Gulf of Mexico assets (described below) do not currently fit with our near term strategy and may not fit with our longer term strategy, given the significant capital requirements and long lead times from initial investment to first production associated with deepwater oil and gas exploration and development activities. We are currently evaluating our deepwater portfolio and may monetize or trade assets in that portfolio.

Longer Term Strategy

Looking to the latter half of 2010 and beyond, as we continue to assess development and additional exploration opportunities and target areas for future growth, we are focused primarily on pursuing opportunities that may be generated within our existing development portfolio. However, we will evaluate strategic opportunities to take advantage of our improved capital structure and enhanced financial flexibility for the purposes of acquiring assets, purchasing interests in undeveloped leaseholds (both through lease sales and otherwise) and participating in third party drilling opportunities on the Gulf of Mexico shelf and in adjacent Gulf Coast onshore areas. We will strive to balance these potential growth opportunities against other opportunities based on rates of return while maintaining a ratio of debt-to-capital that is significantly lower than our recent history.

In support of both our near term and longer term strategies identified above, we have also recently focused seismic expenditures on reprocessing existing 3-D seismic data licensed by us in and around our existing fields, including our East Bay field and fields in the South Timbalier area. We believe that this data will enable us to better image subsurface geological structures, in particular those existing at deeper depths (*i.e.*, below 14,000 to 15,000 feet).

In addition, by developing a core competency in plugging, abandonment and decommissioning operations, we expect to reduce our overall costs in that area of operations, which will enable us to achieve our objective of prudently removing idle infrastructure throughout the remaining productive lives of our fields, particularly in our larger fields such as East Bay. Our chief executive officer has significant experience in conducting these types of

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operations and has staffed our organization to achieve this cost reduction objective. We believe that, as an additional benefit of conducting these operations, we will experience a reduction in LOE over time by removing idle infrastructure and its associated maintenance costs.

Where You Can Find More Information

We maintain a website at *www.eplweb.com* that contains information about us, including links to our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all related amendments as soon as reasonably practicable after providing such reports to the Securities and Exchange Commission (the SEC). In addition, our website contains our Corporate Governance Guidelines and the charters for our Audit, Compensation and Nominating and Governance Committees. Copies of this information are also available by writing to our Corporate Secretary at 201 St. Charles Avenue, Suite 3400, New Orleans, Louisiana 70170. Our website and the information contained in it and connected to it shall not be deemed incorporated by reference into this Annual Report or any other filing that we make with the SEC.

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (as amended, the Exchange Act). The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any document we file with the SEC at *www.sec.gov*.

Our Properties

As of December 31, 2009, we had working interests in 20 producing fields, primarily located in the Gulf of Mexico region. These fields fall into the areas described below:

Gulf of Mexico Shelf

- Eastern offshore area comprised primarily of two producing fields, our East Bay and Main Pass fields;

- Central offshore area comprised of five producing fields, all of which are located in close proximity to each other and are in the vicinity of the Bay Marchand salt dome (the Greater Bay Marchand area); and

- Western offshore area comprised of 10 producing fields extending from offshore central and western Louisiana to Texas.

Deepwater Gulf of Mexico

Our deepwater Gulf of Mexico area is comprised of 22 offshore blocks, including one well at Mississippi Canyon Block 248 that began producing in late 2008.

The Eastern and Central offshore fields and the acreage surrounding them comprise the core of our property base and the focus of our near term efforts.

Gulf of Mexico Shelf

Our East Bay field, the key asset in our Eastern offshore area, comprised approximately 16% of our production during 2009 and 39% of our proved reserves at December 31, 2009, and is located 89 miles southeast of New Orleans near the mouth of the Mississippi River. It contains producing wells located onshore along the

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coastline and in water depths ranging up to approximately 170 feet and is comprised of the South Pass 24, 26 and 27 fields. We operate this field and own an average 99% interest in our acreage position in this area. Our leasehold area covered 33,154 gross acres (32,967 net acres) as of December 31, 2009.

Our Central offshore area, located in the Greater Bay Marchand area, comprised approximately 44% of our production during 2009 and 44% of our proved reserves at December 31, 2009. Our key assets in this area include the South Timbalier 26, 41 and 46 blocks and the Bay Marchand field located approximately 60 miles south of New Orleans in water depths of 181 feet or less. In 2003, we drilled our initial discovery well in the South Timbalier 41 field, in which we hold a 60% working interest, on acreage acquired earlier that year in a federal lease sale. Several exploratory and development wells have been drilled in the field and all but one well has been brought on production. This field, which has additional reserve potential, represents the most significant discovery in our history. We acquired additional acreage in the vicinity of this field in 2005 and subsequent years. At the beginning of 2005 we owned a 50% interest in the South Timbalier 26 field. In March 2005, we closed the acquisition of the remaining 50% interest in South Timbalier 26 above approximately 13,000 feet subsea. As a result of the acquisition, we own a 100% interest in the producing horizons in this field. The acquisition expanded our interest in our core Greater Bay Marchand area and gave us additional flexibility in undertaking the future development of the South Timbalier 26 field.

The properties in the Western offshore area are located in water depths ranging from 7 to 272 feet with working interests ranging from 20% to 100%. In March 2008, we completed the sale of two Gulf of Mexico shelf properties located in our Western offshore area. We owned interests in 10 producing fields in this area as of December 31, 2009.

Deepwater Gulf of Mexico

At December 31, 2009, we owned interests in 22 blocks in the deepwater Gulf of Mexico area. Our working interests in our leases in this area ranged from 15% to 33%. We have identified additional prospects and leads in our deepwater acreage portfolio that we may choose to pursue or to monetize depending on our current evaluation of such deepwater assets. See Financial Condition, Liquidity and Capital Resources in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Oil and Natural Gas Reserves

In December 2008, the SEC issued a final rule, Modernization of Oil and Gas Reporting, which amended its oil and gas reserves estimation and disclosure requirements. The new requirements were codified into the Accounting Standards Codification (ASC) Topic 932, Extractive Activities Oil and Gas (ASC 932), in January 2010, and had the effect of, among other things, modifying the prices used to estimate reserves for SEC disclosure purposes to an average price based upon the prior twelve month period rather than the year-end price. See Note 19 Supplementary Oil and Natural Gas Disclosures (Unaudited) of the consolidated financial statements in Part II, Item 8 of this Annual Report for additional information regarding changes in reporting related to oil and natural gas reserves as a result of ASC 932. The revised rule was effective January 1, 2010 for reporting December 31, 2009 annual oil and natural gas reserve information. We have adopted the provisions of the final rule in connection with the filing of this Annual Report.

The following table presents our estimated net proved oil and natural gas reserves and the estimated future net revenues and cash flows related to our reserves at December 31, 2009 and 2008. Our estimates of proved reserves are based on reserve reports prepared as of December 31, 2009 by the independent petroleum engineering firms Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P. Neither the present values, discounted at 10% per year, of estimated future net cash flows before income taxes (PV-10), or the standardized measure of discounted future net cash flows shown in the table are intended to represent the current market value of the estimated oil and natural gas reserves that we own. Note 19 Supplementary Oil and Natural Gas Disclosures of the consolidated financial statements in Part II, Item 8 of this Annual Report provides important additional information about our proved oil and natural gas reserves.

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PV-10 may be considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. Because the standardized measure is dependent on the unique tax situation of each company, our calculation may not be comparable to those of our competitors. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis.

	As of December 31,	
	2009	2008
	(dollars in thousands)	
Total estimated net proved reserves:		
Oil (Mbbls)	19,923	21,637
Natural gas (Mmcf)	67,378	90,808
Total (Mboe)	31,153	36,771
Net proved developed reserves (1):		
Oil (Mbbls)	15,026	17,052
Natural gas (Mmcf)	57,139	79,413
Total (Mboe)	24,549	30,288
Estimated future net revenues before income taxes (2)	$ 534,771	$ 557,660
Present value of estimated future net revenues before income taxes (2)(3)	$ 395,997	$ 425,247
Standardized measure of discounted future net cash flows (4)	$ 393,802	$ 416,171

(1) Net proved developed non-producing reserves as of December 31, 2009 (7,174 Mbbls and 41,710 Mmcf) were 14,126 Mboe, or 45% of our total proved reserves.
(2) The December 31, 2009 amount was calculated using an oil price of $57.70 per barrel and a natural gas price of $3.96 per Mcf, held constant for the life of the reserves, computed in accordance with ASC 932, based on the simple average of the closing price on the first day of each of the twelve months during the fiscal year. The December 31, 2008 amount was calculated using a period-end oil price of $44.77 per barrel and a period-end natural gas price of $6.05 per Mcf, in accordance with the SEC rules in effect at that time.
(3) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, determined in the manner described in footnote (2), discounted at a rate of 10% per year on a pre-tax basis.
(4) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10% per year, as calculated in accordance with SEC guidelines and pricing.

As of December 31, 2009, our proved-undeveloped reserves (PUDs) totaled 4,897 Mbbls of oil and 10,239 Mmcf of natural gas, for a total of 6,604 MBoe. Included in these PUDs are 4,178 MBoe that have been included in proved-undeveloped reserves for longer than five years. Our PUDs at December 31, 2009, were associated with infill exploitation reserves in proven reservoirs which generally are up-dip reserves and/or reserves where the existing wellbore is not mechanically viable, requiring a new or replacement wellbore to enable production. We expect our PUDs to convert from proved-undeveloped to proved-developed as the planned development projects begin starting in 2010. We estimate that these PUDs will be classified as proved-developed within five years. We project future development costs relating to the development of these PUDs to be approximately $15.5 million in 2010, $29.4 million in 2011, $32.3 million in 2012, $14.9 million in 2013, and $2.6 million thereafter.

Our internal controls used to assure the objectivity of the reserves estimation process includes policies requiring reserve estimates to be in compliance with SEC guidelines. Responsibility for compliance with our policies is held by our Director of Corporate Reserves and Planning. Our reserve estimates are prepared by independent petroleum engineering firms and are reviewed by certain members of senior management.

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Our Director of Corporate Reserves and Planning is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He is a registered petroleum engineer with extensive experience in reservoir analysis and reports directly to our executive management.

As an operator of domestic oil and gas properties, we have filed Department of Energy Form EIA-23, Annual Survey of Oil and Gas Reserves, as required by Public Law 93-275. The differences between the reserves as reported on Form EIA-23 and those reported herein are attributable to the fact that Form EIA-23 requires that an operator report the total reserves attributable to wells that it operates, without regard to percentage ownership and excluding non-operated wells in which it owns an interest.

Costs Incurred in Oil and Natural Gas Activities

The following table sets forth the costs incurred associated with finding, acquiring and developing our proved oil and natural gas reserves.

	Years Ended December 31,	
	2009	2008
	(In thousands)	
Acquisitions Proved	$	$
Acquisitions Unproved	85	20,925
Exploration	2,477	56,202
Development (1)	8,815	127,948
Costs incurred	$ 11,377	$ 205,075

(1) Includes asset retirement obligations incurred associated with finding, acquiring and developing our proved oil and natural gas reserves of $13.4 million during the year ended December 31, 2008. No asset retirement obligations were incurred associated with finding, acquiring and developing our proved oil and natural gas reserves during the year ended December 31, 2009.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2009.

	Total Productive Wells	
	Gross	Net
Oil	193	145
Natural gas	48	28
Total	241	173

Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. Thirty gross oil wells and six gross natural gas wells have dual completions.

In this Annual Report, when referring to wells and acreage, gross refers to the total wells or acres in which we have a working interest and net refers to gross wells or acres multiplied by our working interest.

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Acreage

The following table sets forth information as of December 31, 2009 relating to acreage held by us. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
Gulf of Mexico Shelf		
Eastern offshore area	23,154	22,967
Central offshore area	26,187	16,937
Western offshore area	61,731	39,533
Total Gulf of Mexico Shelf	111,072	79,437
Deepwater Gulf of Mexico	5,760	1,599
Other	640	96
Total	117,472	81,132
Undeveloped:		
Gulf of Mexico Shelf		
Eastern offshore area	10,000	10,000
Central offshore area	63,377	61,107
Western offshore area	74,224	64,145
Total Gulf of Mexico Shelf	147,601	135,252
Deepwater Gulf of Mexico	120,960	30,054
Other	3,526	455
Total	272,087	165,761

Leases covering 26% of our undeveloped net acreage expire in 2010 (primarily related to our Central offshore area), 22% in 2011, 10% in 2012, 34% in 2013, 1% in 2014 and 7% thereafter. See Financial Condition, Liquidity and Capital Resources in Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Drilling Activity

Drilling activity refers to the number of wells completed at any time during the applicable fiscal years, regardless of when drilling was initiated. The term completed refers to the installation of permanent equipment for the production of oil or natural gas. Our 2009 development activities consisted of five gross (3.8 net) successful workovers. We executed one exploration well late in 2009 which was not completed until January 2010. We drilled no development or exploration wells that were completed in 2009. In 2008, we drilled 13 gross (10.6 net) development wells, all of which were productive. Also in 2008, we drilled four gross (0.9 net) exploration wells, of which three gross (0.7 net) were productive and one gross (0.2 net) was non-productive.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, mechanics and materialman liens, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory title to, or rights in, all of our properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. We investigate title prior to the consummation of an acquisition of producing properties and before the

commencement of drilling operations on undeveloped properties. We have obtained or conducted a thorough title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and natural gas industry.

Regulatory Matters

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Regulation of Natural Gas Gathering. Section 1(b) of the Natural Gas Act of 1938, as amended (the NGA), exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission (the FERC) as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the tests the FERC has historically used to establish a pipeline s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts, or Congress. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Regulation of Offshore Gathering Facilities. Our gathering systems gather gas and oil on the Outer Continental Shelf (the OCS) and in Louisiana. Our gathering systems are subject to the jurisdiction of the applicable state regulatory agencies to the extent that those gathering systems traverse state land and/or waters. State regulation of gathering facilities generally includes various safety, environmental, nondiscriminatory take, and common purchaser requirements, and complaint-based rate regulation.

The gathering systems are also subject to the jurisdiction of the MMS, since these gathering systems traverse the OCS pursuant to MMS-issued easements. The MMS issued a final rule, effective August 18, 2008, that implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines on the OCS. We cannot predict the ultimate impact of these regulatory changes to our OCS natural gas operations. We do not believe that we would be affected by any such regulatory changes materially differently than other gathering lines operating on the OCS with whom we compete.

Regulation of Onshore Gathering Facilities. Our onshore natural gas gathering operations are subject to ratable take and common purchaser statutes in the states in which we operate. The common purchaser statutes generally require our gathering pipelines to purchase or take without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. Louisiana and Texas have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. The rates we charge for gathering in Texas and Louisiana are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Though our natural gas gathering facilities are not subject to regulation by the FERC as natural gas companies under the NGA, our gathering facilities may be subject to certain FERC annual natural gas transaction reporting requirements and daily scheduled flow and capacity posting requirements depending on the volume of natural gas transactions and flows in a given period. See the discussion of Other Federal Laws and Regulations Affecting Our Industry FERC Market Transparency Rules.

In 2007, Texas enacted new laws regarding rates, competition and confidentiality for natural gas gathering and transmission pipelines (the Competition Statute) and new informal complaint procedures for challenging determinations of lost and unaccounted for gas by gas gatherers, processors and transporters (the LUG Statute). The Competition Statute gives the Railroad Commission of Texas (the RRC) the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. This statute also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Statute also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Statute modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. Such statute also extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Statute and the LUG Statute became effective September 1, 2007. We cannot predict what effect, if any, these statutes might have on our future operations in Texas.

Regulation of Sales of Natural Gas and Natural Gas Liquids (NGLs). The price at which we buy and sell natural gas and NGLs is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission (the CFTC). See below the discussion of Other Federal Laws and Regulations Affecting Our Industry Energy Policy Act of 2005. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities. In addition, pursuant to Order 704 (as defined below) some of our operations may be required to annually report to the FERC, starting May 1, 2009, information regarding natural gas purchase and sale transactions depending on the volume of natural gas transacted during the prior calendar year. See below the discussion of Other Federal Laws and Regulations Affecting Our Industry FERC Market Transparency Rules.

Regulation of Availability, Terms and Cost of Pipeline Transportation. Our processing operations and our marketing of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and, if a complaint is filed, state regulation. The FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. We cannot predict the ultimate impact of these regulatory changes to our natural gas production operations and our natural gas and NGL marketing operations. We do not believe that we would be affected by any such FERC action materially differently than other natural gas producers and natural gas and NGL marketers with whom we compete.

The ability of our facilities to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, the FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. The FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council (the NGC+ Work Group), or to explain how and why their tariff provisions differ. We do not believe that the adoption of the NGC+ Work Group s gas quality interim guidelines by a pipeline that either directly or indirectly interconnects with our facilities would materially affect our operations. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group s interim guidelines for such an interconnecting pipeline.

Regulation of Transportation of Oil. Our wholly owned subsidiary, EPL Pipeline, L.L.C. (EPL Pipeline), is an interstate common carrier pipeline subject to regulation by the FERC under the Interstate Commerce Act, or ICA . EPL Pipeline owns an approximately twelve-mile pipeline that runs between South Timbalier 26 and a portion of South Timbalier 41 on the Gulf of Mexico OCS to Bayou Fourchon, Louisiana. The ICA requires that we maintain a tariff on file with the FERC for this pipeline. The tariff sets forth the rate, which was established at a negotiated rate that has not been protested, as well as the rules and regulations governing this service. The ICA requires, among other things, that rates on interstate common carrier pipelines be just and reasonable and nondiscriminatory. The ICA permits challenges to existing rates and authorizes the FERC to investigate such rates to determine whether they are just and reasonable. If, upon completion of an investigation, the FERC finds that the existing rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation and, in some cases, reparations for the two year period prior to the filing of a complaint.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005. The Domenici-Barton Energy Policy Act of 2005 (the EPAct 2005) is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. With respect to regulation of natural gas transportation, the EPAct 2005 amended the NGA and the Natural Gas Policy Act of 1978, as amended (the NGPA), by increasing the criminal penalties available for violations of each Act. The EPAct 2005 also added a new section to the NGA, which provides the FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and $1,000,000 per violation per day for violations of the NGPA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce, including our Company. EPAct 2005 also amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by the FERC. In 2006, the FERC issued Order No. 670 (Order 670) to implement the anti-market manipulation provision of EPAct 2005. Order 670 makes it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit any statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. Order 670 does not apply to activities that relate only to non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704 (as defined below) and the daily scheduled flow. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of the FERC s NGA enforcement authority.

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FERC Market Transparency Rules. In 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order 704). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other natural gas companies with whom we compete.

Environmental Regulations

General. Various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended (CERCLA), the Resource Conservation and Recovery Act, as amended (RCRA), the Federal Water Pollution Control Act of 1972, as amended (the Clean Water Act), and the Federal Clean Air Act, as amended (the Clean Air Act), affect our operations and costs. In particular, our exploration, development and production operations, our activities in connection with storage and transportation of oil and other hydrocarbons, and our use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes may be subject to regulation under these and similar state laws and regulations. These laws and regulations:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling and production activities on certain lands lying within wilderness, wetlands and other protected areas;
- impose permitting, monitoring, and recordkeeping requirements and other regulatory controls; and
- impose substantial liabilities for pollution resulting from our operations, including the performance of remedial measures to address pollution as a result of operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties or the imposition of injunctive relief. Changes in environmental laws and regulations occur regularly, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position and the oil and natural gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, there is no assurance that this trend will continue in the future.

As within the industry generally, compliance with existing laws and regulations increases our overall cost of business. The areas affected include:

- unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water;
- capital costs to drill exploration and development wells primarily related to the management and disposal of drilling fluids and other oil and natural gas exploration wastes; and

capital costs to construct, maintain and upgrade equipment and facilities.

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Superfund. CERCLA, also known as Superfund, imposes liability for response costs associated with releases of hazardous substances and damages to natural resources as a result of such releases, without regard to fault or the legality of the original act, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of a disposal site or a site where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the Environmental Protection Agency (EPA) and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur in remediating releases of hazardous substances. 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. The term hazardous substance does not include petroleum, including crude oil or any fraction thereof, unless specifically listed or designated under CERCLA, and the term does not include natural gas, NGLs, liquefied natural gas, or synthetic gas usable for fuel. While this petroleum exclusion lessens the significance of CERCLA to our operations, in the course of our ordinary operations, we may generate waste that may fall within CERCLA s definition of a hazardous substance. We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed.

We currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and, to our knowledge, our predecessors have used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hazardous substances were not under our control. These properties and wastes disposed on these properties could give rise to liability under CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators;
- to clean up contaminated property, including contaminated groundwater;
- to pay for natural resource damages resulting from the releases;
- to perform certain health studies; or
- to perform remedial operations to prevent future contamination.

At this time, we do not believe that we have any liability associated with any Superfund site, and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990, as amended (the OPA), and regulations thereunder impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters, adjoining shorelines, or in the exclusive economic zone of the United States. A responsible party includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150.0 million depending on the risk represented by the quantity or quality of oil that is handled by the facility. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA s requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of the occurrence of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA s financial responsibility and other operating requirements will not have a material adverse effect on us.

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Resource Conservation and Recovery Act. RCRA provides a framework for the disposal of discarded materials and the management of solid and hazardous wastes. RCRA imposes stringent waste management requirements, and liability for failure to meet such requirements, on a person who is either a generator or transporter of hazardous waste or an owner or operator of a hazardous waste treatment, storage or disposal facility. At present, RCRA and many similar state statutes include a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

Clean Water Act. The Clean Water Act imposes restrictions and controls on the discharge of pollutants, including produced water and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants or unauthorized discharges of fill material into wetlands or other waters and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release, for natural resource damages resulting from the release, and for mitigation or restoration related to the filling of wetlands and other waters. We are subject to the Clean Water Act s permitting requirements for discharges associated with exploration and development activities. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Safe Drinking Water Act. The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control Program, authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. In Louisiana and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

National Marine Sanctuary Act, Marine Mammal Protection Act, and Endangered Species Act. Certain federal laws, including the National Marine Sanctuaries Act and the Marine Mammal Protection Act provide special protection to certain designated marine areas and marine species. Executive Order 13158 (Marine Protected Areas), issued in 2000, directs federal agencies to strengthen existing Marine Protected Areas (MPAs), establishes new MPAs, and develops a national system of MPAs. This order could adversely affect our operations by restricting areas in which we may carry out future exploration or production activities and/or cause us to incur increased operating expenses. In addition, MMS permit approvals are conditioned on the collection and removal of debris resulting from activities related to exploration, development and production of offshore leases in order to prevent harm to marine species. The MMS also issues Notices to Lessees and Operators (NTLs) that provide guidance on the implementation of and compliance with Outer Continental Shelf Lands Act (OCSLA) regulations. The MMS has issued numerous NTLs relating to the prevention of harm to marine species, with which we must comply. In addition, certain plants and animals have been classified as threatened or endangered and are protected under the Endangered Species Act (the ESA). The ESA prohibits the take, including harm or harassment, of these protected species and damage to their habitat. If

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endangered species are located in an area in which we conduct operations, our operations could be prohibited, restricted, or delayed, or we could be required to implement expensive mitigation measures.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require federal licenses, permits, and/or other governmental approvals. Several federal statutes, including OCSLA, the National Environmental Policy Act, and the Coastal Zone Management Act require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. The environmental review process required under these laws can be costly and time-consuming and could result in the delay or prohibition of our planned activities.

Lead-Based Paints. Various pieces of equipment and structures owned by us have been coated with lead-based paints as was customary in the industry at the time these pieces of equipment were fabricated and constructed. These paints may contain lead at a concentration high enough to be considered a regulated hazardous waste when removed. If we need to remove such paints in connection with maintenance or other activities and they qualify as a regulated hazardous waste, this would increase the cost of disposal. High lead levels in the paint may also require us to institute certain administrative and/or engineering controls required by the Occupational Safety and Health Act and the MMS to ensure worker safety during paint removal.

Clean Air Act. Our operations utilize equipment that emits air pollutants subject to the federal Clean Air Act and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. We could be required to incur costs in the future for additional air pollution control equipment, although we do not believe that these requirements will have a material adverse effect on our operations. We believe that we are in compliance in all material respects with applicable air pollution requirements.

Climate Change. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, international negotiations to address climate change have occurred. The Kyoto Protocol became effective on February 16, 2005 as a result of these negotiations, but the United States did not ratify the Kyoto Protocol. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17 percent compared to 2005 levels. We continue to monitor the international efforts to address climate change. Their effect on our operations cannot be determined with any certainty at this time.

The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations, prepare an inventory of greenhouse gas emissions resulting from our operations, or pay a tax on the greenhouse gas emissions resulting from our operations. The EPA also is taking steps to regulate greenhouse gas emissions. The EPA has adopted a comprehensive national system for reporting emissions of greenhouse gases for major sources of emissions. EPA has announced that it plans to adopt regulations in 2010 that would impose certain restrictions on greenhouse gas emissions from mobile sources such as cars and trucks and from stationary sources. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions, which could have a material adverse effect on our business and the demand for the oil and natural gas we produce.

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Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower greenhouse gas emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The majority of scientific studies on climate change suggest that stronger storms may occur in the future in the areas where we operate, although the scientific studies are not unanimous. As discussed below in *Plugging, Abandonment and Decommissioning*, we are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Naturally Occurring Radioactive Materials (NORM). NORM are materials whose radioactivity is enhanced by technological processing such as mineral extraction or processing through exploration and production conducted by the oil and natural gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM-contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards.

Plugging, Abandonment and Decommissioning. We are responsible for plugging and abandoning wellbores and decommissioning associated platforms, pipelines and facilities on our oil and natural gas properties. Some of our offshore operations are conducted on federal leases that are administered by the MMS and are required to comply with the regulations and orders promulgated by the MMS under OCSLA.

Recently, the MMS announced that it will commence more stringent enforcement of requirements to decommission facilities that pose a hazard to safety or the environment or are not useful for lease operations and are not capable of oil and natural gas production in paying quantities. Historically, the MMS granted approval to operators to maintain these structures in order to conduct other future activities; however, we expect that this practice will be more limited in the future. The MMS has stated that these measures are in response to the experiences in recent hurricane seasons with damage caused by idle structures. In 2008, we responded to an MMS written request to review and evaluate our inventory of non-producing wells and facilities to determine the future utility of these structures and the level of threat posed to the environment and human safety in the event of a catastrophic loss. As a result, we reviewed a plan with the MMS to perform wellbore plugging and abandonment and decommissioning work on certain facilities and structures in our East Bay field during 2009, 2010 and 2011.

The effects of Hurricanes Katrina and Rita during the 2005 hurricane season and Hurricanes Ike and Gustav in 2008 significantly impacted oil and gas operations on the Outer Continental Shelf. The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The MMS continues to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the MMS issued guidance, through Notices to Lessees, aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, design and operational requirements will be issued by the MMS, and these new requirements could increase our operating costs. The MMS and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse affect on our financial position, results of operations and cash flows.

The failure to comply with these rules and regulations could result in substantial penalties, including lease termination in the case of federal leases. Under limited circumstances, the MMS could require us to suspend or terminate our operations on a federal lease. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations, although the impact of those requirements may vary significantly based on the nature and location of operations and related pipelines and facilities.

Significant Customers

We market substantially all of the oil and natural gas from properties we operate and from properties others operate where our interest is significant. We sell our natural gas to marketing companies pursuant to a variety of contractual arrangements, generally under contracts with terms no longer than six to twelve months. Pricing on those contracts is based largely on published regional index pricing. We sell our oil under contracts with month-to-month terms to a variety of purchasers. The pricing for oil is based upon the posted prices set by major purchasers in the production area, reporting publications, or upon New York Mercantile Exchange (NYMEX) pricing. Oil pricing is adjusted for quality and transportation differentials. Oil and natural gas purchasers are selected on the basis of price, credit quality and service reliability.

Our oil, condensate and natural gas production is sold to a variety of purchasers, historically at market-based prices. We believe that the prices for liquids and natural gas are comparable to market prices in the areas where we have production. Of our total oil and natural gas revenues in 2009, Shell Trading (US) Company accounted for approximately 30%, ChevronTexaco Exploration & Production Company accounted for approximately 27% and Louis Dreyfus Energy Services, L.P. accounted for approximately 19%. Due to the nature of the markets for oil and natural gas, we do not believe that the loss of any one of these customers would have a material adverse effect on our financial condition or results of operations, although a temporary disruption in production revenues could occur.

Employees

As of December 31, 2009, we had 101 full-time employees, including 18 geoscientists, engineers and technicians and 53 field personnel. Our employees are not represented by any labor union or other collective bargaining organization. We consider relations with our employees to be satisfactory and we have never experienced a work stoppage or strike.

As a result of the uncertainties related to our financial condition and certain efforts to downsize our staffing needs, we reduced the number of our employees by 57 through lay-offs and voluntary departures during 2009. We regularly use independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field, on-site production operations and certain accounting functions.

Competitors

Our competitors include numerous independent oil and gas companies, individuals and major oil companies. Many of our larger competitors possess and employ financial and personnel resources substantially greater than ours. These competitors are able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to replace and expand our reserve base depends on our ability to attract and retain qualified personnel and identify and acquire suitable producing properties and prospects for future drilling. See Part I, Item 1A, Risk Factors for additional information about risks related to our competitors, personnel and ability to acquire producing properties and prospects.

Inflation

Prior to the third quarter of 2008, we observed a general rise in the selling prices of our oil and natural gas over the prior three year period due to market factors that include the decline in the value of the U.S. dollar against other currencies, including those from which the U.S. imports oil. During that same period, we also observed increasing prices for drilling services, transportation services and raw materials, such as steel, which have impacted our lease operating expenses and our capital expenditures. The significant decline in commodity prices that occurred in the latter part of 2008, along with a general economic downturn, generally created downward pressure in 2009 on prices for the materials and services that we use in our operations, primarily our exploration, development, plugging, abandonment and other decommissioning activities. The duration and extent of future price changes, declines or increases, is highly uncertain.

Seasonality

Historically, the demand for and price of natural gas generally trends upward during the winter months and downward during the summer months. However, these seasonal fluctuations can be reduced due to summer storage practices where pipeline companies, utilities, distribution companies and industrial users may purchase and place into storage facilities a portion of their anticipated winter requirements of natural gas. These trends are also disrupted by extreme market impacts such as those that occurred in 2008, when oil and natural gas prices reached peak levels in the summer months, then fell during the winter. Tropical storms and hurricanes generally occur in the Gulf of Mexico during late summer and fall, which may require us to evacuate personnel and shut-in production during those periods. The winds and turbulent current conditions that occur in the winter months can impact our ability to safely load, unload and transport personnel and equipment, and perform operations, including plugging, abandonment and other decommissioning activities, which can delay our operations, increase the cost of our operations and/or delay the restoration and maintenance of our oil and natural gas production.

Cautionary Statement Concerning Forward Looking Statements

This Annual Report contains certain forward-looking statements within the meaning of Section 21E of the Exchange Act. When used herein, the words will, would, should, likely, estimates, thinks, strives, may, anticipates, expects, believes, intends, goals, plan expressions are intended to identify forward-looking statements, which are generally not historical in nature. While our management considers the expectations and assumptions to be reasonable when and as made, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- our ability to retain and motivate key executives and other necessary personnel;
- changes in general economic conditions;
- uncertainties in reserve and production estimates;
- unanticipated recovery or production problems;
- hurricane and other weather-related interference with business operations;
- the effects of delays in completion of, or shut-ins of, gas gathering systems, pipelines and processing facilities;
- oil and natural gas prices and competition;
- the impact of derivative positions;

production expense estimates;

cash flow estimates;

future financial performance;

planned and unplanned capital expenditures;

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volatility in the financial and credit markets or in oil and natural gas prices; and

other matters that are discussed in our filings with the SEC.

These statements are based on current expectations and projections about future events and involve known and unknown risks, uncertainties, and other factors that may cause actual results and performance to be materially different from any future results or performance expressed or implied by these forward-looking statements. Investors are cautioned that all such statements involve risks and uncertainties. Our actual decisions, performance and results may differ materially. Important trends or factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those described in the section Risk Factors in Part 1, Item 1A of this Annual Report and elsewhere in this Annual Report; our reports and registration statements filed from time to time with the SEC; and other announcements we make from time to time.

Although we believe that the assumptions on which any forward-looking statements are based in this Annual Report and other periodic reports filed by us are reasonable when and as made, no assurance can be given that such assumptions will prove correct. All forward-looking statements in this Annual Report are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Annual Report and we undertake no obligation to publicly update or revise any forward-looking statements, except as required by applicable securities laws and regulations.

Item 1A. ***Risk Factors***

Risks Relating to Energy Partners, Ltd.

Even though we have successfully entered into the Credit Facility, issued the PIK Notes and emerged from our Chapter 11 reorganization, we will continue to have substantial capital needs that we may not be able to satisfy in the future.

Like other oil and natural gas exploration and production companies, our business has substantial capital requirements. In order to provide us with access to capital immediately following our emergence from our Chapter 11 reorganization, we entered into the Credit Facility and issued the PIK Notes, and we intend to finance our capital expenditures primarily through cash flow from operations. Because our cash flows are subject to a range of economic, competitive and business risks, we may not be able to generate sufficient cash flow from operations to meet our debt payment obligations and to fund these capital requirements. Additionally, the amounts available to us under the Credit Facility may not be sufficient for our capital requirements not funded by initial cash flows, and we may not be able to access additional financing resources for a variety of reasons, including restrictive covenants in the Credit Facility and the general lack of available capital due to the condition of the global credit markets. If we are unable to make scheduled payments on the Credit Facility, or if our financing requirements are not met by the Credit Facility and we are unable to access sources of additional financing on terms we find acceptable, our business, operations, financial condition and cash flows will be negatively impacted.

The restrictive covenants under our Credit Facility and the PIK Notes may limit our ability to take certain actions. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.

Our Credit Facility and the indenture covering the PIK Notes contain various restrictive covenants that limit our ability and the ability of our subsidiaries to take certain actions, including paying dividends, incurring indebtedness and selling or otherwise disposing of assets (including the trade or exchange of oil and natural gas properties). Our ability to comply with these covenants may be affected by events outside of our control, including prevailing economic and financial conditions. If we breach any of these covenants, a default could occur that, if not waived, would entitle certain of our debt holders to declare all amounts then outstanding to be immediately due and payable. If this indebtedness is accelerated, we may not be able to repay the debt or obtain new financing on terms acceptable to us to refinance our debt.

The PIK Notes accrue interest at a relatively high interest rate and there is no assurance we will be able to discharge this debt prior to its maturity date.

The PIK Notes accrue interest at a rate of 20% per year, which is payable in kind on a semi-annual basis by issuing additional notes to our noteholders until the first interest payment date that occurs 91 days after the termination of the Credit Facility. Thereafter, interest is payable quarterly in cash. While we intend to seek to refinance the PIK Notes prior to their maturity date, there is no assurance that we will be able to obtain new financing on terms acceptable to us.

Our actual financial results may vary significantly from the projections filed with the Bankruptcy Court.

In connection with the Plan, we were required to prepare projected financial information to demonstrate to the Bankruptcy Court the feasibility of the Plan and our ability to continue operations upon emergence from our Chapter 11 reorganization. We filed projected financial information with the Bankruptcy Court and furnished it to the SEC as part of the disclosure statement approved by the Bankruptcy Court. Our projections reflected numerous assumptions concerning anticipated future performance and prevailing and anticipated market and economic conditions that were and continue to be beyond our control and that may not materialize. Projections are inherently subject to uncertainties and to a wide variety of significant business, economic and competitive risks. Our actual results will vary from those contemplated by the projections for a variety of reasons. These projections were limited by the information available to us as of the date of the preparation of the projections. Therefore, variations from the projections may be material. The projections filed with the Bankruptcy Court have not been incorporated by reference into this Annual Report and neither those projections nor any version of the disclosure statement should be considered or relied on in connection with the purchase of our common stock.

Because our consolidated financial statements reflect fresh-start accounting adjustments made upon emergence from our Chapter 11 reorganization and because of the effects of the transactions that became effective pursuant to the Plan, financial information in our current and future financial statements will not be comparable to our financial information from prior periods.

In connection with our Chapter 11 reorganization, we adopted fresh-start accounting effective on September 30, 2009 in accordance with ASC Topic 852, Reorganizations. Our adoption of fresh-start accounting resulted in our becoming a new entity for financial reporting purposes. As required by fresh-start accounting, our assets and liabilities have been adjusted to reflect fair value. In addition to fresh-start accounting, our financial statements reflect the effects of all of the transactions implemented by the Plan. Accordingly, our financial statements for periods prior to September 30, 2009 are not comparable with our financial statements for periods on or after September 30, 2009. Furthermore, the estimates and assumptions used to implement fresh-start accounting are inherently subject to significant uncertainties and contingencies beyond our control. Accordingly, we cannot provide assurance that the estimates, assumptions, and values reflected in our valuations will be realized, and our actual results could vary materially.

Our credit ratings were withdrawn and failure to regain and improve our credit ratings could have a material adverse effect on our business.

In 2009, Moody s Investors Service downgraded each of our Corporate Family Rating and Probability of Default Rating to default levels or equivalent and withdrew its ratings due to our Chapter 11 reorganization. The decline and withdrawal of our credit ratings reflected concerns over our financial strength. Our current credit ratings status reduces our access to the debt markets and may unfavorably impact our overall cost of borrowing.

Recent adverse publicity about us, including publicity regarding our Chapter 11 reorganization, may harm our ability to compete in a highly competitive environment.

Adverse publicity regarding our financial condition and our Chapter 11 reorganization, may adversely affect our ability to attract new customers and to maintain favorable relationships with existing customers, suppliers and partners. For example, it may be more challenging for us to engage in risk sharing transactions, and some of

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our suppliers may require cash payments rather than extending credit, which adversely affects our liquidity. Furthermore, our recent Chapter 11 reorganization may adversely affect our ability to negotiate favorable terms from our operating partners and other parties and to attract and retain employees, each of which could in turn adversely affect our financial performance.

Our asset carrying values have been impaired based, in part, on oil and natural gas prices as of December 31, 2008 and March 31, 2009 and they may be further impaired if oil and gas prices decline from prices in effect as of those dates or those used to estimate the fair values of our oil and gas properties for fresh-start accounting as of September 30, 2009.

The substantial decline in oil and gas prices and reduced capital spending on certain fields based on this lower price environment in 2008 and continuing in 2009 impacted the estimated net cash flows from our oil and natural gas reserves, which estimates were used to determine impairments of our oil and natural gas properties. As a result of the decline in oil and gas prices, we revised our estimated reserves downward and significantly reduced our estimated future cash flows. Based in part on our 2008 year-end estimates of proved reserves, we recorded a non-cash pre-tax impairment charge of $108.6 million in the fourth quarter of 2008. We recorded additional impairment charges totaling $8.5 million and $8.1 million in the periods from October 1, 2009 through December 31, 2009 and from January 1, 2009 through September 30, 2009, respectively. We applied fresh-start accounting as of September 30, 2009 and recorded our oil and gas properties at their respective estimated fair values as of that date. In some cases, the estimated fair values exceeded the net book values, in part, because of changes in estimated future selling prices of oil and gas as of September 30, 2009, as compared to prior periods. We may be required to recognize additional non-cash pre-tax impairment charges in future reporting periods if market prices for oil or natural gas continue to decline or based on other factors, including our ability to fund capital expenditures required to maintain our oil and natural gas reserves.

Our current operations are concentrated in the Gulf of Mexico, and a significant part of the value of our production and reserves is concentrated in two geographic areas. Because of this concentration, any production problems or inaccuracies in reserve estimates related to these areas could have a material adverse effect on our business.

Virtually all of our current operations are concentrated in the Gulf of Mexico region. We are more vulnerable to operational, regulatory and other risks associated with the Gulf of Mexico, including the risk of adverse weather conditions, than many of our competitors that are more geographically diversified because all or a substantial portion of our operations could experience the same condition at the same time.

During 2009, 44% of our net daily production came from our Greater Bay Marchand area properties and approximately 44% of our proved reserves were located in the fields that comprise this area. In addition, 16% of our net daily production came from our East Bay field and approximately 39% of our proved reserves were located in this area. If the actual reserves associated with these two properties are less than our estimated reserves, such a reduction of reserves could have a material adverse effect on our business, financial condition, results of operations and cash flows.

During the 2008 hurricane season, our production was reduced by approximately 21%, on an annual basis, as a result of damage to third party pipelines caused by two hurricanes. The hurricane damage limited our ability to sell our production from certain properties for extended periods of time during the third and fourth quarters of 2008. If mechanical problems, storms or other events were to curtail a substantial portion of the production in these areas, such a curtailment could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We may not regain exempt status from MMS regulations requiring bonds or other surety in support of our offshore decommissioning obligations.

For offshore operations, a lessee must comply with MMS regulations governing, among other things, plugging and abandonment of wells and removal of facilities. The MMS generally requires that a lessee meet

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certain financial criteria or else post bonds or other assurances that it can meet such decommissioning obligations. Shortly before we began the Chapter 11 reorganization process, the MMS ordered us to shut in the federal portion of our East Bay field as a result of our failure to comply with these bonding requirements. While we have considerably greater financial flexibility and an improved balance sheet as a result of our Chapter 11 reorganization, there is no assurance that we will be granted exempt status. If it is not granted, the costs associated with providing these bonds is substantial and, should we fail to provide these bonds, the MMS could again require us to shut in production from certain of our federal leases.

The relatively steep decline curves generally associated with oil and gas properties located in the Gulf of Mexico and the Gulf Coast region subjects us to higher reserve replacement needs.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High initial production rates generally result in recovery of a relatively higher percentage of reserves from properties during the initial few years of production, often followed by a rapid decline in the rate of production.

Because substantially all of our operations are concentrated in the Gulf of Mexico and because production from reservoirs in the Gulf of Mexico region generally declines more rapidly compared to reservoirs in many other producing regions of the world, our reserve replacement needs are relatively greater than those of producers with reserves outside the Gulf of Mexico region.

As of December 31, 2009, our independent petroleum engineers estimate that, on average, 65% of our total proved reserves will be produced within five years. We may not be able to develop, exploit, find or acquire additional reserves to sustain our current production levels or to grow our production. In addition, we significantly reduced our capital expenditures in 2009 in order to conserve cash resources, which will likely negatively impact our ability to replace existing reserves that are being depleted by current production. Our initial budgeted capital expenditures for 2010 remain at levels significantly lower than our historical averages. There can be no assurance that we will be able to grow production at rates we have experienced in the past. Our future oil and natural gas reserves and production, results of operations and cash flows are highly dependent on our ability to efficiently develop and exploit our current reserves and economically find or acquire additional recoverable reserves.

Our exploration, exploitation and production operations in the deepwater Gulf of Mexico area present unique operating risks.

The deepwater Gulf of Mexico area is an area that has had relatively limited drilling activity due to risks associated with geological complexity, water depth and higher drilling and development costs, which could result in substantial cost overruns and/or uneconomic projects or wells, including:

- an extended length of time between drilling and first production as compared to typical shallow to moderate-water depth projects;
- drilling that requires specific types of rigs with significantly higher day rates and limited availability as compared to the rigs used in shallow water;
- more costly consequences of mechanical failure because of the equipment required to operate at the water depths and adverse conditions found in the deepwater Gulf of Mexico area;
- mechanical risks because the wellhead equipment is installed on the sea floor;
- many reservoirs are sub-salt and are more difficult to detect with traditional seismic processing; and
- larger installation equipment, sophisticated sea floor production handling equipment, expensive, state-of-the-art platforms and/or infrastructure investment.

Because we have exploration, exploitation and production operations in the deepwater Gulf of Mexico area, we are exposed to these risks. Furthermore, because of the generally higher expense of drilling wells in the

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deepwater Gulf of Mexico area, if such wells are economically unsuccessful, they may have a larger impact on our financial condition, results of operations and cash flows than wells that we drill in shallow water. Although we are currently evaluating our deepwater portfolio and may monetize or trade assets in that portfolio, there is no assurance that we will be able to do so on terms acceptable to us.

Properties we have acquired may not produce as projected, and we may not have fully identified liabilities associated with these properties or obtained adequate protection from sellers against liabilities.

In the past, we acquired producing properties from third parties, and these acquisitions required us to assess many factors that are inherently inexact and may be inaccurate, including:

- the amount of recoverable reserves and the rates at which those reserves will be produced;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging, abandonment and other decommissioning activities; and
- potential environmental and other liabilities.

Our assessments may not have revealed all existing or potential problems with the properties or permitted us to become adequately familiar with the properties in order to evaluate fully their deficiencies and capabilities. In the course of our due diligence, we may not have inspected every well, platform or pipeline. Our inspections may not have identified structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not have obtained contractual indemnities from the seller for liabilities that it created. We may have assumed the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Periods of high cost or lack of availability of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute on a timely basis our exploration and development plans.

Substantially all of our current operations are concentrated in the Gulf of Mexico region. Shortages and the high cost of drilling rigs, equipment, supplies or personnel that occur in this region from time to time could delay or adversely affect our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations or cash flows. Periodically, as a result of increased drilling activity or a decrease in the supply of equipment, materials and services, we have experienced increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. Increased drilling activity in the Gulf of Mexico and in other offshore areas around the world also decreases the availability of offshore rigs in the Gulf of Mexico. As a result, costs may increase in the future and necessary equipment and services may not be available on terms acceptable to us.

Loss of key management and failure to attract qualified management could negatively impact our operations.

Successfully implementing our strategies will depend, in part, on our management team. The loss of members of our management team could have an adverse effect on our business.

Our ability to pay dividends is restricted by covenants in our Credit Facility and the indenture related to the PIK Notes.

The covenants in certain debt instruments to which we are a party, including the Credit Facility and the indenture related to the PIK Notes, place certain restrictions and conditions on our ability to pay dividends. Certain institutional investors may invest only in dividend-paying equity securities or may operate under other restrictions that may prohibit or limit their ability to invest in us. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

The existence of some provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our Certificate of Incorporation and Bylaws that could delay or prevent an unsolicited change in control of our company include:

- the Board s ability to issue shares of preferred stock and determine the terms of the preferred stock without approval of common stockholders; and

- a prohibition on the right of stockholders to call meetings and limitations on the right of stockholders to present proposals or make nominations at stockholder meetings.

In addition, Delaware law imposes some restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

Our common stock is thinly traded and ownership is primarily concentrated in a few holders.

Our stock trades on the New York Stock Exchange. However, as a result of our Chapter 11 reorganization, the majority of our common stock is concentrated in a few institutional stockholders and our trading volume is generally low. There has been a limited public market for our common stock and we cannot assure you that an active trading market for our stock will develop or, if one develops, will be maintained. The price of our common stock may be affected by a limited trading volume and may fluctuate significantly, and the absence of an active trading market may adversely affect our stockholders ability to sell our common stock in short time periods, or possibly at all.

Our 2009 year-end estimates of oil and natural gas reserves are not directly comparable to our prior estimates because of new reporting rules, and our interpretations of the new rules may differ materially from future guidance or comments issued by the SEC.

The year-end 2009 estimates of proved oil and natural gas reserves presented in this Annual Report have been prepared using new SEC disclosure rules that differ in a number of respects from prior rules. As a result of changes in the reporting rules, our reserve estimates beginning with year-end 2009 will not be directly comparable to our previously-reported reserves.

The SEC has not reviewed our reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this Annual Report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Risks Relating to the Oil and Natural Gas Industry

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

Our future success will depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing and operating

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wells is often uncertain before drilling commences. Overruns in planned expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling activity, including the following:

- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices;
- title problems;
- limitations in the market for oil and natural gas; and
- cost of services to drill wells.

Any continuing volatility in the financial and credit markets, or in oil and natural gas prices, may affect our ability to obtain funding or to obtain funding on acceptable terms. These factors may hinder or prevent us from meeting our future capital needs and/or continuing to meet our obligations and conduct our business.

Global financial markets and economic conditions have recently been, and could continue to be, disrupted and volatile. The debt and equity capital markets have become exceedingly distressed. These issues, along with significant asset write-offs in the financial services sector, the re-pricing of credit risk and the continuing weak economic conditions, have made, and will likely continue to make, it difficult to obtain debt or equity capital funding. There can be no assurance that funding will be available to us if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due, implement our exploration and development plan, enhance our existing 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, financial position and cash flows.

A substantial or extended decline in oil and natural gas prices may have a material adverse effect on our business, financial condition, results of operations, cash flows and our ability to meet our debt obligations, operating cost requirements, capital expenditure requirements and other financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, financial condition, cash flow, access to capital and future rate of growth. Oil and natural gas are commodities and, as a result, 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. While oil and natural gas prices have recently recovered from their low levels in 2009, there are different views about the strength of the economic recovery and future demand for oil and natural gas. Consequently, there is no assurance that prices will not fall again. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include:

changes in the global supply, demand and inventories of oil;

domestic natural gas supply, demand and inventories;

the actions of the Organization of Petroleum Exporting Countries;

the price and quantity of foreign imports of oil;

the price and availability of liquefied natural gas imports;

political conditions, including embargoes, in or affecting other oil-producing countries;

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- economic and energy infrastructure disruptions caused by actual or threatened acts of war, or terrorist activities, or national security measures deployed to protect the United States from such actual or threatened acts or activities;
- economic stability of major oil and natural gas companies and the interdependence of oil and natural gas and energy trading companies;
- the level of worldwide oil and natural gas exploration and production activity;
- weather conditions, including energy infrastructure disruptions resulting from those conditions;
- technological advances effecting energy consumption; and
- the price and availability of alternative fuels.

Oil and natural gas prices as of the date of this Annual Report permit us to maintain the minimal investment necessary to maintain our current production levels. However, if prices fall to their previous low levels, we may not be able to replace our reserves and our production may decline significantly. As a result, we could continue to experience a decline in our revenues and available capital, which will substantially decrease our capital expenditures, drilling activities and operations.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Our insurance coverage may not be sufficient or may not be available to cover some of these losses and claims.

Losses and liabilities arising from uninsured and underinsured events could materially and adversely effect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties;
- fires and explosions;
- personal injuries and death; and
- natural disasters, especially hurricanes and tropical storms in the Gulf of Mexico region.

Offshore operations are also subject to a variety of operating risks unique to the marine environment, such as capsizing, collisions and damage or loss from hurricanes, tropical storms or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses. We maintain insurance at levels that we believe are consistent with industry practices and our particular needs, but we are not fully insured against all risks. We may elect not to obtain insurance for certain risks or to limit levels of coverage if we believe that the cost of available insurance is excessive relative to the risks involved. For example, due to limited availability of insurance coverage at commercially acceptable rates, we no longer maintain business interruption insurance. In this regard, the cost of available coverage has increased significantly as a result of losses experienced by third party insurers in the 2005 and 2008 hurricane seasons in the Gulf of Mexico, in particular those resulting from Hurricanes Katrina and Rita in 2005 and Gustav and Ike in 2008. We believe the cost of coverage will continue to increase and may become prohibitively expensive for smaller independent operators in the Gulf of Mexico. As a result, our coverage may be limited by higher deductibles on property damage and other types of insurance. In addition, pollution and environmental risks generally are not

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fully insurable. If a significant accident or other event occurs and it is not fully covered by insurance, it could adversely affect our financial condition, results of operations and cash flows and could reduce or eliminate the funds available for exploration, exploitation and acquisitions or result in loss of equipment and properties.

Reserve estimates depend 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 estimated values of our reserves.

The process of estimating oil and natural gas reserves is complex, requiring interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves disclosed in this Annual Report.

Estimates of oil and natural gas reserves are inherently imprecise. The preparation of our reserve estimates requires projections of production rates and timing of development expenditures, analysis of available geological, geophysical, production and engineering data, and assumptions about oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The extent, quality and reliability of this data can vary. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, drilling and operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates.

The present value of future net revenues from our proved reserves and the standardized measure of discounted future net cash flows referred to in this Annual Report should not be assumed to represent or approximate the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from our proved reserves are computed using prices based on the simple average of the closing price on the first day of each of the twelve months during the fiscal year and costs as of the date of the estimate held constant for the life of the reserves. Actual future prices and costs may differ materially from those used in our reserve estimates.

If our estimates of the recoverable reserve volumes on a property are revised downward, if development costs exceed previous estimates or if commodity prices decrease, as discussed elsewhere in these risk factors, we may be required to record an impairment to our property and equipment, which could have a material adverse effect on our financial position and results of operations. Once recorded, an impairment of property and equipment may not be reversed at a later date. Our ability to obtain financing depends in part on our estimate of the proved oil and natural gas reserves for properties that will serve as collateral. If proved reserves on a property are revised downward, our ability to acquire adequate funding may be significantly reduced.

If we are unable to replace the reserves that we have produced, our reserves and future revenues will decline.

Our future success depends on our ability to find, develop, acquire and produce oil and natural gas reserves that are economically recoverable. Lower commodity prices and increased costs associated with exploration and production may lower the threshold of economic recoverability. Additionally, we substantially cut our capital expenditures in 2009 and our initially budgeted 2010 capital expenditures are significantly lower than our historical averages, which will likely negatively impact our ability to replace existing reserves produced. Without continued successful acquisition or exploration activities, our reserves and revenues will decline as a result of our current reserves being depleted by production. We may not be able to find or acquire additional reserves on an economic basis.

Our business requires substantial capital investment and maintenance expenditures, and our capital resources may not be adequate to provide for all of our cash requirements.

Our operations are capital intensive. Our ability to replace our oil and natural gas production and maintain our production levels and reserves requires extensive capital investment. Our business also requires substantial

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expenditures for routine maintenance. We may not have access to the capital required to maintain our production levels and reserves.

Impediments to transporting our products may limit our access to oil and natural gas markets or delay our production.

Our ability to market our oil and natural gas production depends on a number of factors, including the proximity of our reserves to pipelines and terminal facilities, the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties and the availability of satisfactory oil and natural gas transportation arrangements. These facilities and systems may be shut-in due to factors outside of our control. If any of these third party services and arrangements become partially or fully unavailable, or if we are unable to secure such services and arrangements on acceptable terms, our production could be limited or delayed and our revenues could be adversely affected.

Our ability to collect payments from our partners depends on the partners creditworthiness.

In operating our oil and natural gas properties, we typically incur costs on behalf of our partners in advance of billing and collecting our partners share of those costs. Some of our partners are highly leveraged and may become unable to pay us for their share of the operating costs. Further, a significant adverse change in the financial and/or credit position of a partner could require us to assume greater credit risk relating to that partner and could limit our ability to collect joint interest receivables. Failure to receive payments from our partners for their share of costs incurred on our oil and natural gas properties could adversely affect our results of operations, financial condition and cash flows.

We are exposed to counterparty risk through our hedging activities using commodity derivative instruments and through other arrangements we enter into with financial and other institutions.

We have entered into transactions with counterparties such as commercial banks, investment banks, insurance companies, and other financial institutions. These transactions expose us to credit risk in the event of default of any of these counterparties. Continued deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

When we have oil and natural gas derivative contracts outstanding, we have exposure to these financial institutions related to such contracts, which may protect a portion of our cash flows when commodity prices decline. During periods of low oil and natural gas prices, we may have heightened counterparty risk associated with these derivative contracts because the value of our derivative positions may provide a significant amount of cash flow. If a hedging counterparty defaults on its obligations, we may not realize the benefit of some or all of our derivative instruments.

We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. If an insurer defaults on its obligation to us, we may not be reimbursed for losses we have insured against. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity may be reduced by an amount up to the aggregate amount of such lender s commitment under our credit facility.

We are subject to extensive governmental laws and regulations, including environmental regulations, that can adversely affect the cost, manner or feasibility of doing business and could result in restrictions on our operations or civil or criminal liability.

Our exploration, development and production operations, our activities in connection with storage and transportation of oil and other hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes are subject to various federal, state and local laws, orders and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties or the imposition of injunctive relief.

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Future compliance with laws and regulations, including environmental, production, transportation, sales, rate and tax rules and regulations, and any changes to such laws or regulations, may reduce our profitability and have a material adverse effect on our financial position, liquidity and cash flows. Such laws and regulations may require more stringent and costly waste handling, storage, transport, disposal or cleanup requirements. See Part I, Item 1, Business Environmental Regulations in this Annual Report.

The proposed U.S. federal budget for fiscal year 2011 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 1, 2010, the Obama administration released its proposed federal budget for fiscal year 2011. The proposed budget would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new taxes. The provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; levy of an excise tax on Gulf of Mexico oil and gas production; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands.

If these proposals are enacted, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities. Since none of these proposals has yet to be voted on or become law, we do not know the ultimate impact any of these proposals may have on our business.

The adoption of pending climate change legislation could result in increased operating costs, create delays in our obtaining air pollution permits for new or modified facilities, and reduce demand for the crude oil and natural gas we produce.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill. The Senate s version, The Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been introduced, but has not passed. Although these bills include several differences that require reconciliation before becoming law, both bills contain the basic feature of establishing a cap and trade system for restricting greenhouse gas emissions in the United States. Under such a system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission allowances corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this legislative initiative remains uncertain. In addition to the pending climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect on January 1, 2010 and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an Endangerment Finding under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has proposed regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities, and may issue final rules this year. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce.

Derivatives regulation could restrict our ability to execute commodity derivative instruments as a hedge against fluctuating commodity prices.

Various measures are being proposed by committees of the U.S. Congress, the U.S. Treasury Department, and other agencies to restrict the use of over-the-counter (OTC) derivative instruments. These proposals include, but are not limited to, requiring cash collateral on all OTC derivatives and requiring all OTC derivatives to be executed and settled through an exchange system. Although we do not currently know the exact form any final legislation or rule-making activity will take, any restriction on the use of OTC instruments could have a significant impact on our business.

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Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack at our facilities, or those of our customers, could have a material adverse affect on our financial condition and operations.

If third party pipelines and other facilities interconnected to our natural gas pipelines and facilities become partially or fully unavailable to transport natural gas and NGLs, our revenues could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation is not within our control. If any of these third party pipelines and other facilities become partially or fully unavailable to transport natural gas and NGLs, or if the gas quality specification for their pipelines or facilities changes so as to restrict our ability to transport gas on these pipelines or facilities, our revenues could be adversely affected.

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

Our operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects our non-FERC jurisdictional businesses and the markets for products derived from these businesses. The FERC has recently issued Order 704 requiring certain participants in the natural gas market, including interstate and intrastate pipelines, natural gas gatherers, natural gas marketers, and natural gas processors, that engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to the FERC.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. The FERC s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to transportation capacity.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to establish a pipeline s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts, or Congress. In addition, the courts have determined that certain pipelines that would otherwise be subject to the ICA are exempt from regulation by the FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of our gathering facilities and transportation pipelines may be subject to change based on future determinations by the FERC, the courts, or Congress.

The MMS has communicated that it will commence more stringent enforcement of requirements to decommission facilities that pose a hazard to safety or the environment or are not useful for lease operations and are not capable of oil and natural gas production in paying quantities. Historically, the MMS granted approval to operators to maintain such facilities in order to conduct other future activities. However, we expect that this

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practice will be more limited in the future. The MMS has stated that these measures are in response to recent hurricane seasons in which idle structures were damaged or destroyed. We recently responded to an MMS written request to review and evaluate our inventory of non-producing wells and facilities to determine the future utility of these structures and the level of threat posed to the environment and human safety in the event of a catastrophic loss. As a result, we reviewed a plan with the MMS to perform wellbore plugging and abandonment and decommissioning work on certain facilities and structures in our East Bay field during 2009, 2010 and 2011.

The MMS and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows.

The failure to comply with these rules and regulations can result in substantial penalties, including lease termination in the case of federal leases. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations, though the impact of those requirements may vary significantly based on the nature and location of operations and related pipelines and facilities.

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 EPAct 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have traditionally not been subject to full FERC regulation, the FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Competition in the oil and natural gas industry is intense, which may adversely affect us.

We operate in a highly competitive environment for acquiring oil and natural gas properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in Gulf of Mexico and Gulf Coast onshore activities. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to define, 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 discover 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. There can be no assurance that we will be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. If we are unable to compete successfully in these areas in the future, our revenues and growth may be diminished or restricted.

Item 1B. ***Unresolved Staff Comments***

None.

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Item 2. ***Properties***

The information contained in Part I, Item 1, Business of this Annual Report is incorporated by reference.

Item 3. ***Legal Proceedings***

For information regarding legal proceedings, see the information in Note 16, Commitments and Contingencies in the consolidated financial statements in Part II, Item 8 of this Annual Report.

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PART II

Item 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Since September 23, 2009, the common stock of the reorganized Company (the Successor Company) has been listed on the New York Stock Exchange (the NYSE) under the symbol EPL. During the period from March 30, 2009 through September 21, 2009, our common stock was quoted for public trading on the Pink Sheets quotations system, an over-the-counter market, under the symbol ERPLQ.PK. Prior to March 30, 2009, the common stock of the pre-reorganized Company (the Predecessor Company) was listed on the NYSE under the symbol EPL. The following table sets forth, for the periods indicated, the range of the high and low sales prices of our common stock as reported by the NYSE (through the First Quarter 2009 and subsequent to September 22, 2009) and the Pink Sheets quotations system (subsequent to First Quarter 2009 through September 21, 2009).

	High ($)	Low ($)
Predecessor Company		
2008		
First Quarter	12.71	8.04
Second Quarter	16.50	9.24
Third Quarter	15.46	8.00
Fourth Quarter	8.91	1.19
2009		
First Quarter	2.34	0.08
Second Quarter	0.45	0.05
Third Quarter (through September 21, 2009)	0.47	0.27
Successor Company		
2009		
Third Quarter (from September 23 to September 30, 2009)	11.73	6.81
Fourth Quarter	9.39	7.25
2010		
First Quarter (through March 8, 2010)	11.24	8.28

On March 8, 2010, the last reported sale price of our common stock on the NYSE was $10.80 per share.

As of March 8, 2010, there were approximately 170 holders of record of our common stock.

We have not paid any cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including the Credit Facility and the indenture related to the PIK Notes, place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2009, with respect to compensation plans under which our equity securities are authorized for issuance.

	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (1)	Weighted Average Exercise Price of Outstanding Options Warrants and Rights (2)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by stockholders			
Equity compensation plans not approved by stockholders (3)	89,846	$ 10.00	1,121,258
Total	89,846	$ 10.00	1,121,258

(1) Comprised of 68,116 shares subject to issuance upon the exercise of options and 21,730 shares to be issued upon the lapsing of restrictions associated with restricted share awards.
(2) Restricted share awards do not have an exercise price; therefore, this only reflects the weighted-average option exercise price.
(3) The form of the 2009 Long Term Incentive Plan was filed with the Plan Supplement and approved by the Bankruptcy Court prior to our emergence from Chapter 11 reorganization. Accordingly, no stockholder approval was required, and none was sought or obtained.

See Note 15 Employee Benefit Plans of the consolidated financial statements in Part II, Item 8 of this Annual Report for further information regarding the significant features of the above plan.

Item 6. ***Selected Financial Data***

Not required of smaller reporting companies.

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

General

We were incorporated as a Delaware corporation in January 1998 and operate in a single segment as an independent oil and natural gas exploration and production company. Our current operations are concentrated in the shallow to moderate depth waters in the Gulf of Mexico focusing on the areas offshore Louisiana as well as the deepwater Gulf of Mexico in depths less than 5,000 feet.

Basis of Presentation

In accordance with ASC Topic 852, Reorganizations (ASC 852), we adopted fresh-start accounting as of September 30, 2009. Fresh-start accounting is required upon a substantive change in control and requires that the reporting entity allocate the reorganization value of the Company to its assets and liabilities in relation to their fair values. Under the provisions of fresh-start accounting, a new entity has been deemed created for financial reporting purposes. In this Annual Report, references to the Predecessor Company refer to reporting dates of the Company through September 30, 2009, including the effect of the provisions of the Plan and the application of fresh-start accounting; activity of the Company subsequent to September 30, 2009 is referred to as that of the Successor Company.

Recent Events

Impact of the Chapter 11 Reorganization on Management and Conduct of Our Business. Our reorganization under Chapter 11 in 2009 substantially reduced our indebtedness and restructured our balance

sheet. Throughout the course of our Chapter 11 reorganization, we continued to operate in the ordinary course of business without the sale of any assets and continued to meet our business obligations to our vendors and joint interest owners. As a result of our Chapter 11 reorganization, the Company now has an improved capital structure and enhanced financial flexibility.

We emerged from our Chapter 11 reorganization with a five-member board of directors whose members were appointed by operation of the Plan with the approval of the Bankruptcy Court. The Board includes members with significant experience in the oil and gas exploration and production industry. On the Exit Date, the Board appointed a new chief executive officer to lead our executive management team. See Recent Events in Item 1, Part I of this annual report for more information on our board of directors and chief executive officer.

During 2009, including the period following our emergence from Chapter 11 reorganization, we undertook meaningful cost reductions in G&A expenses and LOE. These cost reductions included significant reductions both in our workforce and office space in our New Orleans and Houston offices, reductions in the use of third party contractors and consultants, lower marine transportation and liftboat costs and lower corporate governance costs.

We have entered 2010 with a continuing focus on achieving meaningful cost reductions in G&A expenses and LOE, converting non-producing reserves to cash flow, developing a core competency in plugging, abandonment and decommissioning operations and evaluating opportunities while allocating capital in a rigorous and disciplined manner intended to achieve an overall lower risk capital expenditure profile. Our process for allocating capital focuses on maximizing rate of return and requires projects to compete on that basis.

We believe that we have identified sufficient exploitation opportunities such that our 2010 average oil production levels will equal or exceed our 2009 levels. However, we expect our overall natural gas production to decline in 2010 as a result of natural gas production declines that occurred in the second half of 2009 and are expected to continue into 2010. Management has defined an initial low risk capital budget oriented towards stabilizing production at the levels experienced in the quarter ended December 31, 2009 and expects to continue to develop additional production enhancing opportunities to be considered in 2010 and 2011. Management will consider recommending to the Board additional capital projects that we expect could move us from forecasted production declines in 2010 toward the maintenance of current production levels.

Longer term, as we continue to assess development opportunities and target areas for future growth, we are focused primarily on pursuing opportunities that may be generated from within our existing development portfolio. However, we will evaluate strategic opportunities to take advantage of our improved capital structure and enhanced financial flexibility for the purposes of acquiring assets, purchasing interests in undeveloped leaseholds (both through lease sales and otherwise) and participating in third party drilling opportunities to complement our existing asset base. We will strive to balance these potential growth opportunities against opportunities to reduce our overall indebtedness and/or maintain a ratio of debt-to-capital that is significantly lower than our recent historical experience.

We are also focused on the development of a core competency in plugging, abandonment and decommissioning operations in an attempt to reduce our overall costs in that area of operations, which will enable us to achieve our objectives of prudently removing idle infrastructure throughout the remaining productive lives of our fields and, over time, to reduce ongoing LOE associated with maintaining idle infrastructure. Our expenditures for plugging, abandonment and other decommissioning activities undertaken in 2009 totaled approximately $24 million. We expect our expenditures for plugging, abandonment and other decommissioning activities in 2010 to total approximately $10.8 million. Most of our planned 2010 plugging, abandonment and decommissioning activities are expected to occur at our East Bay field. We have $12.9 million remaining in restricted escrow funds for decommissioning work in our East Bay field, $6.9 million of which will be available for draw currently upon completion of certain decommissioning activities as that work progresses. The remaining $6.0 million will remain restricted until substantially all required decommissioning in the East Bay field is complete. To date, we have drawn approximately $3.8 million from these funds.

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Background to Chapter 11 Reorganization. Our filing for reorganization under Chapter 11 was preceded by a number of events and economic conditions that negatively impacted our business and liquidity, including the following:

- hurricanes in August and September of 2008 damaged third party production pipelines, causing us to shut-in a significant amount of our production from September 2008 and continuing into early 2009;

- oil and natural gas prices declined in the fourth quarter of 2008 and remained at relatively low levels during 2009 relative to the levels in 2008; and

- the worldwide credit and capital markets collapsed in 2008 and the availability of debt and equity financing became significantly more scarce, thus reducing financial flexibility for most companies, including us.

These factors negatively impacted our business, and led to several circumstances that significantly affected our liquidity and led to our filing for Chapter 11 reorganization, including:

- in the third quarter of 2008, the MMS rejected our request for a waiver of supplemental bonding requirements for the decommissioning of certain of our federal offshore properties, resulting in the requirement for us to provide cash or other financial support totaling $47.3 million. As a result, the MMS issued an order to us on March 23, 2009 (the MMS Order) that resulted in the shut-in of the federal portion of our East Bay field;

- in March 2009, we received a notice of redetermination from Bank of America, N.A., the Administrative Agent under the Predecessor Company s Credit Agreement dated as of April 23, 2007 (the Pre-Reorganization Credit Agreement), that our borrowing base under the Pre-Reorganization Credit Agreement had been reduced from $150 million to $45 million, resulting in a borrowing base deficiency of $38 million that was required to be repaid by April 3, 2009 (which date was ultimately extended to May 1, 2009); and

- on April 15, 2009, we were required to make scheduled interest payments of approximately $17 million on the Predecessor Company s 9.75% Senior Unsecured Notes due 2014 and its Senior Floating Notes due 2013.

Our inability to satisfy these obligations in a timely manner ultimately led to our filing for reorganization under Chapter 11.

Emergence from Chapter 11 Reorganization. On the Exit Date, we consummated certain transactions contemplated by the Plan and entered into the Credit Facility, which consists of the Revolver and a $25 million one-year amortizing term loan facility and the MMS Order was rescinded. On the Exit Date, we drew $25 million under the Revolver. We also issued the PIK Notes, which were issued with original issue discount and yielded proceeds of $55.0 million after the discount. The proceeds from the Credit Facility and the PIK Notes were used to repay amounts outstanding of $83 million under the Pre-Reorganization Credit Agreement and to provide working capital for the Company. We subsequently delivered to the MMS the financial support related to abandonment obligations on certain federal leases in the Gulf of Mexico and we resumed production from the federal portion of the East Bay field. As a result of our improved capital structure, we expect to regain our waiver of supplemental bonding requirements for the decommissioning of our federal offshore properties.

In connection with our emergence from our Chapter 11 reorganization, on the Exit Date we converted the Predecessor Company s 9.75% Senior Unsecured Notes due 2014, its Senior Floating Rate Notes due 2013 and its 8.75% Senior Notes due 2010, in an aggregate principal amount of approximately $455 million (collectively the Predecessor Company Notes) and all outstanding shares of the Predecessor Company s common stock into shares of the Successor Company s common stock. In accordance with the terms of the Plan, the Predecessor Company Notes and related indentures were cancelled and each existing holder of the Predecessor Company Notes received, in exchange for such holder s claim (including principal and accrued interest), such holder s pro

rata portion of approximately 95% of the Successor Company s common stock. Each holder of shares of the Predecessor Company s common stock received, in full satisfaction of and in exchange for such holder s interest in the common stock of the Predecessor Company, such holder s pro rata portion of approximately 5% of the Successor Company s common stock.

See Financial Condition, Liquidity and Capital Resources for information regarding the Successor Company s equity capitalization and capital resources. In addition, our Chapter 11 reorganization and related matters are addressed in Note 3, Reorganization and Fresh-Start Accounting in our consolidated financial statements in Item 8, Financial Statements and Supplementary Data.

Overview and Outlook

Our Chapter 11 reorganization did not result in the disposition of any of our oil and natural gas properties. As a result, the comparability of certain components of our operating results and key operating performance measures, specifically those related to production, average oil and natural gas selling prices, revenues and lease operating expenses, was not significantly impacted by the reorganization. In the following discussion, references to the combined annual operations for the year ended December 31, 2009 combine the periods from January 1, 2009 through September 30, 2009 (reflecting the operations of the Predecessor Company) with the period from October 1, 2009 through December 31, 2009 (reflecting the operations of the Successor Company). The combined results of operations for the year ended December 31, 2009 represents a non-GAAP financial measure due to our reorganization and the application of fresh-start accounting. For accounting purposes, the Predecessor Company s operations are deemed to have ceased on September 30, 2009 and a new entity began operations as of that date. As a result, the consolidated financial statements of the Predecessor Company are not comparable to those of the Successor Company. However, we believe that presenting the Predecessor Company s results of operations and cash flows with those of the Successor Company on a combined basis for the two periods is useful when analyzing certain measures of our performance. For those items that are not comparable, we have included additional analysis to supplement the discussion. The following line items in our consolidated statements of operations for the year and quarter ended December 31, 2009 are not comparable to any prior annual or quarterly periods due to our reorganization and application of fresh-start accounting:

- *Depreciation, depletion and amortization;*
- *Accretion of liability for asset retirement obligations;*
- *Interest expense;*
- *Loss from operations;*
- *Loss before reorganization items, loss on discharge of debt, fresh-start adjustments and income taxes; and*
- *Net loss.*

Results of Operations

During the year ended December 31, 2009, we performed five workover operations, four of which were performed in our core fields during the second half of 2009. We completed drilling operations on one exploration well in the Western offshore area in early January 2010. We significantly curtailed our drilling operations beginning in the fourth quarter of 2008 and remained at significantly curtailed drilling activity levels during 2009 due to the factors impacting our liquidity addressed under Recent Events Background to Chapter 11 Reorganization.

Our operating results for the year ended December 31, 2009, compared to the year ended December 31, 2008, reflect significantly lower average selling prices for our oil and natural gas.

For the year ended December 31, 2009, our revenues declined 46% as compared to the year ended December 31, 2008 due primarily to significantly lower average selling prices for our production. Our overall

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production volumes increased by 14% for the year ended December 31, 2009 when compared to the year ended December 31, 2008 primarily due to new deepwater production, which averaged 1,694 Boe per day in the year ended December 31, 2009, along with the impact of the hurricanes curtailing our production in the latter half of 2008.

We performed four successful workovers in the second half of 2009 in our core Central offshore area which contributed to a 16% increase in production from this area in the quarter ended December 31, 2009 to 7,313 Boe per day, as compared to the quarter ended September 30, 2009. Additionally, our production enhancement efforts in our core Eastern offshore area resulted in a 27% increase in production from this area in the quarter ended December 31, 2009 to 2,616 Boe per day, as compared to the quarter ended September 30, 2009. These activities partially offset our 53% decline to 2,143 Boe per day, in production from the Western offshore area for the quarter ended December 31, 2009 as compared to the quarter ended September 30, 2009, which was due primarily to natural declines in several natural gas wells and mechanical problems in another well that represented 23% of our production from this area in the quarter ended September 30, 2009.

In addition to the items addressed above, our loss before reorganization items, loss on discharge of debt, fresh-start adjustments and income taxes for the year ended December 31, 2009 as compared to the year ended December 31, 2008 reflects significant declines in LOE, exploration expenditures and dry hole costs, impairments, G&A expenses and loss on abandonment activities. Our interest expense declined in the year ended December 31, 2009 as compared to the year ended December 31, 2008 primarily because we discontinued recording interest expense related to the Predecessor Company Notes as of May 1, 2009, the date on which we filed for Chapter 11 reorganization. Our loss on derivative instruments, primarily unrealized, was primarily due to changes in the fair values of derivative instruments due to an increase in the market price of oil during the fourth quarter of 2009.

Our effective tax rate for the nine months ended September 30, 2009 was zero because we provided a valuation allowance against the net deferred tax assets generated during the period. Our effective tax rate for the quarter ended December 31, 2009 was an approximately 35% benefit on the loss before income taxes for the quarter as a result of the change in our net deferred tax position due to the reorganization. The impact of the reorganization on our deferred tax position is more fully addressed in Note 14, Income Taxes, of the consolidated financial statements in Item 8, Part II of this Annual Report. Our future income taxes may be materially impacted by our reorganization.

As more fully addressed in Notes 1, 2 and 3 of the consolidated financial statements in Item 8, Part II of this Annual Report, due to our reorganization, amounts reported in our balance sheet as of December 31, 2009 have changed materially from amounts reported as of December 31, 2008. The reorganization and application of ASC 852 adjustments included conversion of the principal and accrued interest on the Predecessor Company Notes into shares of the Successor Company s common stock. We discontinued accruing interest on Predecessor Company Notes as of May 1, 2009, the date we filed for reorganization. Additionally, along with all of our assets and liabilities, our property and equipment assets and our asset retirement obligations were adjusted to reflect fair values as of September 30, 2009. As a result, our interest expense, accretion of liability for asset retirement obligations and depreciation, depletion and amortization following the reorganization are not comparable to those amounts recorded prior to the reorganization.

Our reported operating expenses for the year ended December 31, 2009, and most notably our G&A expenses, were materially impacted by the presentation of the reorganization items separately from operating income as required by ASC 852. Our reorganization items are disclosed in Note 4 of the consolidated financial statements in Item 8, Part II of this Annual Report. Additionally, our net loss for the year ended December 31, 2009 was materially impacted by the adjustments resulting from the reorganization and application of ASC 852 to reflect the loss on discharge of debt and the fresh-start adjustments.

Cash Flows

Our operating cash flows for the year ended December 31, 2009 compared to the year ended December 31, 2008 primarily reflect significantly lower average selling prices for our oil and natural gas. In addition, during

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the year ended December 31, 2009, we made cash payments for reorganization items totaling approximately $18.9 million, which are reflected in our net cash provided by operating activities.

Outlook

We continue to generate prospects, strive to maintain an extensive inventory of drillable prospects in-house and maintain exposure to new opportunities through relationships with industry partners. Generally, we attempt to fund any exploration and development expenditures with internally generated cash flows; however, during the latter part of 2008 and early 2009, we used our Pre-Reorganization Credit Agreement to fund working capital needs as further discussed under the caption Financial Condition, Liquidity and Capital Resources. The Pre-Reorganization Credit Agreement was repaid in full in connection with our emergence from our Chapter 11 reorganization on the Exit Date.

We expect drilling activities in 2010 to be higher than in 2009. Our longer term operating strategy is to increase our oil and natural gas reserves and production while focusing on reducing exploration and development costs and operating costs to be competitive with our industry peers. During the year ended December 31, 2009, we were successful in all of our workover operations. We expect the 2010 drilling program as contemplated by our initial authorized capital budget of approximately $45 million for exploration and development expenditures will be comprised predominately of lower risk development and exploitation opportunities in order to stabilize production.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as oil and natural gas prices, tropical weather, economic, political and regulatory developments and availability of other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil and natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. See Risk Factors in Item 1A for a more detailed discussion of these risks.

We use the successful efforts method of accounting for our investment in oil and natural gas properties. Under this method, we capitalize lease acquisition costs, costs to drill and complete exploration wells in which proven reserves are discovered and costs to drill and complete development wells. Exploratory drilling costs are charged to expense if and when the well is determined not to have found reserves in commercial quantities. Seismic, geological and geophysical, and delay rental expenditures are expensed as incurred. We conduct many of our exploration and development activities jointly with others and, accordingly, recorded amounts for our oil and natural gas properties reflect only our proportionate interest in such activities.

Tropical Weather Impact

In late August and early September 2008, Hurricanes Gustav and Ike traversed the Gulf of Mexico and adjacent land areas. As a result of these two hurricanes, nearly all of our production was shut-in at one time or another during the third and fourth quarters of 2008. We maintain insurance coverage for property damage due to windstorms (such as hurricanes) with a deductible of $20 million per occurrence and an aggregate limit of $55 million. In order to mitigate the higher cost of insurance coverages in 2009, we negotiated higher deductibles and significantly lower aggregates for property damage due to windstorms. Due to limited availability of insurance coverage at commercially acceptable rates, we no longer maintain business interruption insurance.

Dispositions

In March 2008, we completed the sale of two Gulf of Mexico Shelf properties located in our Western offshore area for $15.0 million after giving effect to preliminary closing adjustments. We recorded a gain on the sales of $7.1 million.

We have included the results of operations of the dispositions discussed above through their closing dates. We experienced substantial revenue and production fluctuations as a result of these dispositions and the tropical weather impacts discussed above. For these reasons, as well as those addressed above regarding the application of fresh-start accounting, the comparability of our historical results of operations with future periods may be materially impacted.

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Results of Operations

The following table presents information about our results of operations and should be read in conjunction with the analysis below.

(In thousands)	Successor Company Period from October 1, 2009 through December 31, 2009	Predecessor Company Period from January 1, 2009 through September 30, 2009	Non-GAAP Combined Results for the Year Ended December 31, 2009	Predecessor Company Year Ended December 31, 2008
Revenue:				
Oil and natural gas	$ 56,708	$ 134,583	$ 191,291	$ 356,022
Other	42	302	344	230
	56,750	134,885	191,635	356,252
Costs and expenses:				
Lease operating	13,410	46,296	59,706	71,931
Transportation	315	699	1,014	1,089
Exploration expenditures and dry hole costs	453	1,650	2,103	30,199
Impairments	8,514	8,082	16,596	110,403
Depreciation, depletion and amortization	28,448	95,944	124,392	103,318
Accretion of liability for asset retirement obligations	3,024	5,536	8,560	4,370
General and administrative	4,537	19,493	24,030	37,308
Taxes, other than on earnings	2,083	5,987	8,070	11,245
Gain on sale of assets				(5,527)
Loss on abandonment activities	493	3,732	4,225	21,695
Other	(4)	(26)	(30)	
Total costs and expenses	61,273	187,393	248,666	386,031
Business interruption recovery		1,185	1,185	4,248
Loss from operations	(4,523)	(51,323)	(55,846)	(25,531)
Other income (expense):				
Interest income	3	47	50	784
Interest expense (contractual interest of $34,076 for the period from January 1, 2009 through September 30, 2009)	(4,322)	(17,813)	(22,135)	(46,533)
Gain (loss) on derivative instruments	(22,705)	2,728	(19,977)	2,053
	(27,024)	(15,038)	(42,062)	(43,696)
Loss before reorganization items, loss on discharge of debt, fresh-start adjustments and income taxes	(31,547)	(66,361)	(97,908)	(69,227)
Reorganization items	(865)	(24,198)	(25,063)	
Loss on discharge of debt		(2,666)	(2,666)	
Fresh-start adjustments		57,111	57,111	
Loss before income taxes	(32,412)	(36,114)	(68,526)	(69,227)
Income tax benefit	11,400		11,400	17,015
Net loss	(21,012)	(36,114)	(57,126)	(52,212)

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The following table presents information about our oil and natural gas operations.

	Period from October 1, 2009 through December 31, 2009	Period from January 1, 2009 through September 30, 2009	Non-GAAP Combined Year Ended December 31, 2009	Year Ended December 31, 2008
Net production (per day):				
Oil (Bbls)	6,091	5,127	5,370	5,608
Natural gas (Mcf)	45,726	61,029	57,172	45,070
Total (Boe)	13,712	15,299	14,899	13,120
Average sales prices:				
Oil (per Bbl)	$ 68.03	$ 49.88	$ 55.07	$ 97.42
Natural gas (per Mcf)	4.42	3.89	3.99	9.46
Total (per Boe)	44.95	32.22	35.18	74.15
Impact of derivatives settled during the period (1):				
Oil (per Bbl)	$ (1.73)	$ 1.82	$ 0.80	$ (7.85)
Natural gas (per Mcf)		0.01	0.01	0.02
Oil & natural gas revenues (in thousands):				
Oil	$ 38,121	$ 69,812	$ 107,933	$ 199,948
Natural gas	18,587	64,771	83,358	156,074
Total	56,708	134,583	191,291	356,022
Average costs (per Boe):				
LOE	$ 10.63	$ 11.09	$ 10.98	$ 14.98
Depreciation, depletion, and amortization (DD&A)	22.55	22.97	22.88	21.52
Accretion of liability for asset retirement obligations	2.40	1.33	1.57	0.91
Taxes, other than on earnings	1.65	1.43	1.48	2.34
G&A expenses	3.60	4.67	4.42	7.77
Increase (decrease) in oil and natural gas revenue due to:				
Change in prices of oil			$ (87,203)	
Change in production volumes of oil			(4,812)	
Total decrease in oil sales			(92,015)	
Change in prices of natural gas			(90,428)	
Change in production volumes of natural gas			17,712	
Total decrease in natural gas sales			(72,716)	
Total estimated net proved reserves:				
Oil (Mbbls)			19,923	21,637
Natural gas (Mmcf)			67,378	90,808
Total (Mboe)			31,153	36,771
Standardized measure of discounted future net cash flows (in thousands)			$ 393,802	$ 416,171

(1) See Other Income and Expense section for further discussion of the impact of derivative instruments.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenues and Net Income (Loss)

Our oil and natural gas revenues declined primarily as a result of the 53% decline in average selling prices for our oil and natural gas in the year ended December 31, 2009, as compared to the year ended December 31, 2008. Production increased by 14% in the year ended December 31, 2009 as compared to the year ended

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December 31, 2008, due primarily to new deepwater production, which averaged 1,694 Boe per day in the year ended December 31, 2009, along with the impact of the hurricanes curtailing our production in the latter half of 2008 which reduced our 2008 production by approximately 2,800 Boe per day. In addition to these factors, the change in Loss before reorganization items, loss on discharge of debt, fresh-start adjustments and income taxes in the year ended December 31, 2009 as compared to the year ended December 31, 2008 was primarily attributable to:

- declines in LOE, exploration expenses and dry hole costs, impairments, G&A expenses, and losses on abandonment activities;
- increases in depreciation, depletion and amortization and accretion of liability for asset retirement obligations; and
- losses, primarily unrealized, on changes in the fair values of derivative instruments.

Operating Expenses

LOE decreased in the year ended December 31, 2009, as compared to the year ended December 31, 2008, primarily due to fewer workovers in 2009 and ongoing efforts to reduce LOE costs during 2009.

Exploration expenditures and dry hole costs decreased in the year ended December 31, 2009, as compared to the year ended December 31, 2008, reflecting a significant decline in drilling activity in 2009. We expect our exploration expenditures and dry hole costs to remain at or near their 2009 levels in 2010, due to our currently budgeted levels of exploratory drilling. Our exploratory expenditures and dry hole costs will vary significantly depending on the amount of our capital expenditures dedicated to exploration activities and the level of success we achieve in exploratory drilling activities.

Impairment expense for the Predecessor Company for 2009 is primarily due to amounts recorded in the quarter ended March 31, 2009 related to two producing fields which were determined to have future net cash flows less than their carrying values due to commodity price declines and reservoir performance. Impairment expense recorded by the Successor Company in the quarter ended December 31, 2009 is primarily related to two wells in our Western offshore area, one of which was unsuccessfully recompleted in 2010; the other was determined to be mechanically unable to produce a behind-pipe reservoir. We periodically assess our oil and natural gas assets for impairment based on factors described in Discussion of Critical Accounting Policies. The factors that can result in impairment include declines in the estimated future selling prices of oil and natural gas. Due to our reorganization and application of fresh-start accounting, we recorded our oil and natural gas properties in the consolidated balance sheet of the Successor Company at their estimated fair market values, based on assumptions including the estimates of future oil and natural gas prices as of September 30, 2009. As a result, our capitalized oil and natural gas property costs may be more sensitive to future material impairments than those of other companies in our industry.

Our DD&A was impacted by our reorganization and application of fresh-start accounting. Thus, changes in DD&A and DD&A rates are not comparable for the periods presented. Generally, because oil prices were higher as of September 30, 2009, the date at which we applied fresh-start accounting, as compared to oil prices as of December 31, 2008, a date at which we recorded significant impairments of certain of our oil and natural gas properties, we expect our DD&A rates on our oil properties to be higher for the Successor Company. We anticipate that our DD&A in 2010 will increase in total and on a per Boe basis.

Our reported asset retirement obligations were impacted by our reorganization and application of fresh-start accounting. We estimate our asset retirement obligations based on factors described in Discussion of Critical Accounting Policies. The accretion of liability for asset retirement obligations is significantly impacted by the credit-adjusted risk-free discount rate applied to our estimated future costs to plug, abandon and decommission our oil and natural gas properties. As a result of our reorganization, the credit adjusted risk-free rate we used as

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of September 30, 2009 was significantly higher than the rates used to record asset retirement obligations in prior periods. As a result, we expect the amount of future accretion of the liability for asset retirement obligations to be significantly higher than amounts reported in prior years.

G&A expenses, which includes cash and non-cash stock based compensation of $4.3 million and $7.4 million in the year ended December 31, 2009 and 2008, respectively, decreased in the year ended December 31, 2009 from the year ended December 31, 2008, primarily as a result of a decrease in personnel and consulting costs, offset, in part, by an increase in insurance costs.

Taxes, other than on earnings, decreased in the year ended December 31, 2009 as compared to the year ended December 31, 2008, due primarily to lower average sales prices for oil (which is taxed based on value), offset, in part, by an increase in local property tax assessments. These taxes may fluctuate from period to period depending on our production volumes from non-federal leases and commodity prices received.

Our loss on abandonment activities in the year ended December 31, 2009 primarily resulted from mechanical issues related to well and platform abandonments on two fields in our Western offshore area.

Other Income and Expense

Our interest expense was impacted by our reorganization and is not comparable for the periods presented. Interest expense decreased in the year ended December 31, 2009, as compared to the year ended December 31, 2008, primarily because we discontinued accruing interest on the Predecessor Company Notes as of the date we filed for reorganization under Chapter 11 and discharged the Predecessor Company Notes in the Chapter 11 reorganization. We expect our effective interest rate on borrowings will be higher in 2010 than in prior years due to the higher rate applicable to the PIK Notes, which were issued to yield an approximate 23% effective rate to maturity.

The Predecessor Company settled all outstanding derivative instruments prior to or shortly following our filing for reorganization, realizing a gain on those instruments due to the low price environment existing at the time of settlement. In connection with entering into the Credit Facility on the Exit Date, we entered into derivative instruments, primarily oil swaps, pursuant to terms set forth in the Credit Facility. Due to an increase in the market prices for oil during the fourth quarter of 2009, the Successor Company recorded net unrealized losses on derivative instruments of $21.7 million and losses on settlements of $1.0 million in the fourth quarter of 2009. Other income (expense) in the year ended December 31, 2008 includes an unrealized gain of $19.1 million due to the change in fair market value of derivative instruments which were to be settled in the future and a loss of $17.0 million in derivative instruments settled during 2008 for a total net gain of $2.1 million.

Reorganization Items, Loss on Discharge of Debt and Fresh-Start Adjustments

Under ASC 852, certain costs and income items resulting from the reorganization and related to the Chapter 11 proceedings are reported separately as reorganization items classified as non-operating expenses. For the year ended December 31, 2009, our reorganization items totaled approximately $25.1 million, consisting primarily of $15.2 million in professional fees related to our financial and legal advisors and $6.8 million from the write-off of deferred financing costs associated with the Predecessor Company s Pre-Reorganization Credit Agreement.

The restructuring of the Company s capital and resulting discharge of the Predecessor Company Notes and related accrued interest resulted in a loss on discharge of debt of $2.7 million during 2009.

In order to reflect the adoption of fresh-start reporting pursuant to ASC 852, we adjusted the book values of the Predecessor Company s assets and liabilities to reflect the estimated fair values of the Successor Company s assets and liabilities, on a net basis. These fresh-start adjustments decreased our net loss by $57.1 million during 2009.

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Financial Condition, Liquidity and Capital Resources

Liquidity and Capital Resources

As of December 31, 2009, we had cash and cash equivalents of $26.7 million and no borrowings outstanding under the Revolver. The undrawn commitment under the Revolver was $45 million as of that date. We had total indebtedness of $77.3 million (net of $5.9 million of unamortized original issue discount on the PIK Notes) consisting of $18.8 million remaining on the term loan component of the Credit Facility and $58.5 million related to the PIK Notes. As of the date of this Annual Report, the cash and cash equivalents on our balance sheet has increased and we have continued to reduce the amounts outstanding under the Credit Facility as we continue to amortize the term loan portion thereof.

As of December 31, 2009, the Credit Facility had a borrowing base of $63.8 million, consisting of $45 million plus the $18.8 million remaining principal balance on the term loan. The borrowing base is subject to semi-annual redeterminations based on the proved reserves of the oil and gas properties that serve as collateral for the Credit Facility. We were subject to our first borrowing base redetermination beginning in December 2009, and our borrowing base has been reaffirmed at $45 million plus the remaining principal balance on the term loan. Monthly scheduled repayments of the term loan, each in the amount of $2.1 million, reduce the borrowing base by the principal amount of each such repayment.

As described above under Emergence from Chapter 11 Reorganization, on the Exit Date, we emerged from Chapter 11 reorganization pursuant to the Plan. The reorganization pursuant to the Plan included the following:

- a total of approximately $455 million in principal amount of outstanding Predecessor Company Notes and $18 million of interest accrued and recorded through the date we filed for reorganization under Chapter 11 (as well as additional interest accrued but not recorded from the date we filed for reorganization through the Exit Date) was converted into approximately 95% of the new common stock (or 38 million shares) of the Successor Company;

- the Predecessor Company s common stock was converted into approximately 5% of the common stock (or approximately two million shares) of the Successor Company issued pursuant to the Plan;

- we entered into the Credit Facility;

- we issued the PIK Notes with an aggregate principal amount of $61.1 million, for net proceeds of $55 million; and

- we paid $83.0 million in principal and $1.1 million in interest outstanding under the Pre-Reorganization Credit Agreement.

Of the $25 million drawn at closing under the Revolver, we used approximately $6.3 million to pay pre-petition vendor claims.

A summary of the key terms of our new borrowings is provided in Note 10, Indebtedness in the consolidated financial statements in Item 8, Part II of this Annual Report. We were in compliance with the covenants in our debt agreements as of December 31, 2009.

For 2010, we have an initial authorized capital budget of approximately $57 million, of which approximately $45 million is allocated for exploration and development expenditures and $12 million for plugging, abandonment and other decommissioning expenditures. This initial capital budget is focused on maximizing the return from existing development opportunities and converting nonproducing reserves, primarily oil reserves, to production and positive cash flow. Our near term goal through these efforts is to stabilize existing production levels that are subject to natural reservoir declines. These activities are more heavily weighted toward the first half of the year. As the year progresses, and as we evaluate the initial results of our capital expenditure program, our budget may be increased to fund additional development or exploration opportunities to the extent we have cash available in excess of that contemplated by the initial capital budget.

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Our initial capital expenditure budget does not include any acquisitions, for which we do not budget, or deepwater activities. Capital expenditures on our deepwater portfolio do not currently fit with our near term strategy and may not fit with our longer term strategy, given the significant capital requirements and long lead times from initial investment to first production associated with deepwater oil and gas exploration and development activities. We are currently evaluating our deepwater portfolio and may monetize or trade assets in that portfolio. However, we maintain our rights to participate in the development of our deepwater discoveries until we elect not to proceed with such development plans as may be proposed by the operator of the properties in accordance with the applicable joint operating agreements.

We expect our 2010 cash flows from operations to increase as compared with our operating cash flows for the year ended December 31, 2009, primarily as a result of higher anticipated sales prices for oil and natural gas. We expect our cash used in investing activities for 2010 will increase as compared with our investing cash flows for the year ended December 31, 2009, as a result of our planned increase in capital expenditures in 2010 positively impacting reserve replacement in 2010 and production enhancement. We expect our initial efforts will focus on reducing production declines. We expect these activities may stabilize or reverse our declining production from certain properties in our core areas through the end of 2010. We expect that our deepwater production will continue to decline in 2010.

We have experienced and expect to again experience substantial working capital deficits. We had a working capital deficit of $16.9 million at December 31, 2009. Our working capital deficits have historically resulted from increased accounts payable and accrued expenses related to ongoing exploration and development costs, which may be capitalized as noncurrent assets.

We maintain restricted escrow funds in a trust for future plugging, abandonment and other decommissioning costs at our East Bay field. The trust was originally funded with $15 million and, with accumulated interest, had increased to $16.7 million at December 31, 2008. We have made draws to date of $3.4 million in 2009 and $0.4 million in 2010. We may draw from the trust upon the authorization, and subsequent completion, of qualifying abandonment activities at our East Bay field. We have $12.9 million remaining in restricted escrow funds for decommissioning work in our East Bay field, $6.9 million of which will be available for draw upon completion of certain decommissioning activities as that work progresses. The remaining $6.0 million will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in restricted cash on our consolidated balance sheets.

Shortly following our emergence from Chapter 11 reorganization, we provided the MMS with surety bonds in support of decommissioning obligations on certain federal leases in the Gulf of Mexico, and we resumed production from the federal portion of the East Bay field. We expect our improved financial condition to result in our qualifying for a financial waiver of MMS supplemental bonding requirements in 2010, which would result in reductions in our surety bond costs and a release of related surety bond collateral.

The MMS and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows. See the Risk Factor *A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase* in Part I, Item 1A of this Annual Report.

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Analysis of 2009 Cash Flows

	Period from October 1 through December 31, 2009	Period from January 1 through September 30, 2009	Non-GAAP Combined Year Ended December 31, 2009	Year Ended December 31, 2008
		(in thousands)		
Net cash provided by operating activities	$ 16,868	$ 14,366	$ 31,234	$ 184,610
Net cash used in investing activities	(2,808)	(29,751)	(32,559)	(205,230)
Net cash provided by (used in) financing activities	(31,250)	57,329	26,079	13,747

The decrease in our 2009 cash flows from operations primarily reflects the impact of the precipitous decline in oil and natural gas sales prices realized during the year ended December 31, 2009 as compared to the year ended December 31, 2008.

Net cash used in investing activities declined in the year ended December 31, 2009 as compared to the year ended December 31, 2008 as a result of curtailed capital expenditures in response to declining oil and natural gas sales prices, contraction in the credit markets and reduced liquidity.

Net cash provided by financing activities increased during the year ended December 31, 2009, as compared to the year ended December 31, 2008, as a result of new borrowings arranged pursuant to the Plan.

We have not paid any cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including the Credit Facility and the indenture related to the PIK Notes, place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Disclosures about Contractual Obligations and Commercial Commitments

The following table aggregates the contractual commitments and commercial obligations which affect our financial condition and liquidity position as of December 31, 2009.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	Thereafter
			(In thousands)		
Indebtedness (1)	$ 122,639	$ 18,750	$	$ 103,889	$
Interest on indebtedness (2)	46,687	514		46,173	
Operating leases	4,094	559	1,251	1,249	1,035
Asset retirement obligations including accretion (3)	227,303	10,830	34,296	30,551	151,626
Total contractual obligations	$ 400,723	$ 30,653	$ 35,547	$ 181,862	$ 152,661

(1) Includes obligations for additions to principal on PIK Notes as a result of in-kind interest payments. See Note 10, Indebtedness, to the consolidated financial statements in Part II, Item 8 of this Annual Report for additional information regarding interest on the PIK Notes.

(2) Interest attributable to the Credit Facility was calculated using the rates in effect as of December 31, 2009. Interest attributable to the PIK Notes includes interest on additions to principal as described in (1) above.

(3) Includes discretionary amounts that we expect to spend on asset retirement activities of approximately $8.0 million, $16.4 million and $17.0 million in the less than one year period, one to three year period and three to five year period, respectively.

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Off-Balance Sheet Transactions

We do not maintain any off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources other than those disclosed above.

Derivative Instruments

Note 2 Summary of Significant Accounting Policies and Note 12 Derivative Transactions in Part II, Item 8 of this Annual Report describe our commodity price risks and the instruments we use to manage them.

We enter into derivative instruments to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions can expose us to risk of financial loss if, among other things, production is less than expected, the counterparty to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the derivative instrument and actual price received. Derivative instruments may limit the benefit we would have otherwise received from increases in the sales prices of our oil and natural gas. Conversely, if we were not to engage in hedging transactions, we may be more adversely affected by declines in oil and natural gas prices than our competitors who do engage in hedging transactions.

Our revenues, profitability and future growth are highly dependent on prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under the Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

Discussion of Critical Accounting Policies

In preparing our financial statements in accordance with accounting principles generally accepted in the United States, management must make estimates and assumptions related to the reporting of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Application of certain of our accounting policies requires a significant number of estimates. These accounting policies are described below.

> *Reorganization and Fresh-Start Accounting* The financial statements for the period in which we were in reorganization under Chapter 11 were prepared in accordance with ASC 852, Reorganizations, (originally issued as the American Institute of Certified Public Accountant s Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code). Under ASC 852, we must, among other things, (1) identify transactions that are directly associated with the reorganization from those events that occur during the normal course of business, (2) identify pre-petition liabilities subject to compromise from those that are not subject to compromise or are post petition liabilities and (3) apply fresh-start accounting rules upon emergence from Chapter 11 reorganization.

In accordance with ASC 852, we adopted fresh-start accounting as of September 30, 2009. Fresh-start accounting is required upon a substantive change in control and requires that the reporting entity allocate the reorganization value of the Company to its assets and liabilities in relation to their fair values. Under the provisions of fresh-start accounting, a new entity has been deemed created for financial reporting purposes.

Based on financial projections that we and our advisors developed, the allocation of the reorganization value was determined using various valuation methods, including (i) comparable company analysis, which estimates the value of the Company based on the implied valuations of other similar companies; (ii) comparable asset transaction analysis, which estimates the value of a company based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of a company based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis, which estimates the value of the Company by determining the present value of estimated future cash flows. The reorganization value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties and contingencies which are beyond our control. The fair value allocated to our property and equipment should not be viewed as representative of the current value of our oil and natural gas reserves or the current value of the Company. The reorganization value of the Company was estimated to be approximately $603 million.

In order to reflect the reorganization and application of ASC 852, we adjusted the book values of the Predecessor Company s assets and liabilities to reflect the estimated fair values of the Successor Company s assets and liabilities, on a net basis. These adjustments reduced our net loss by $57.1 million. The restructuring of the Company s capital and resulting discharge of the Predecessor Company Notes and related accrued interest resulted in a loss of $2.7 million. The adjustments for the revaluation of the assets and liabilities and the loss on the discharge of pre-petition debt are recorded in Fresh-start adjustments and Loss on discharge of debt, respectively, in the consolidated statement of operations for the period from January 1, 2009 through September 30, 2009.

Successful-Efforts Method of Accounting Oil and natural gas exploration and production companies choose from two acceptable methods of accounting for oil and gas properties, the successful-efforts method, which is the method we use, and the full cost method. The most significant difference between the two methods relates to the accounting treatment of drilling costs incurred on unsuccessful exploratory wells (dry holes) and exploration costs. Under the successful efforts method of accounting for oil and natural gas producing activities, costs to acquire mineral interests in oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. We may capitalize exploratory well costs beyond one year if (a) we found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project; otherwise, these costs are expensed. Geological and geophysical costs are charged to expense as incurred. We allocate the capitalized cost of producing oil and gas properties to earnings through DD&A on a field-by-field basis as production occurs. Entities that follow the full cost method capitalize drilling and exploratory costs, including dry hole costs, into one or more large pools of oil and natural gas property costs. Under the full cost method, the capitalized costs for each pool are allocated to earnings through DD&A based on the production of each pool. Additionally, under the successful efforts method, we measure impairments of our oil and natural gas properties based on the estimated fair value of oil and natural gas properties on a field-by-field basis based on the requirements of ASC Topic 360, Property, Plant and Equipment. In estimating fair value, we make assumptions about factors that have a high degree of uncertainty, including expected future sales prices for oil and natural gas, expected future costs of production, development and abandonment, and the appropriate rate at which we discount future cash flows. Under the full cost method, impairments are measured based on criteria determined by the SEC, which differs from the application of ASC Topic 360.

We believe that companies with active exploratory drilling programs typically incur dry hole costs. To the extent that we incur significant amounts of exploratory drilling costs in the future, we expect to continue to incur dry hole costs in the future. We expect our dry hole costs will vary depending on our success rate in finding productive oil and natural gas reserves as well as the amount of our capital expenditures that are dedicated to exploration activities.

Proved Reserve Estimates We use our oil and natural gas proved reserve estimates to calculate our DD&A. We allocate the capitalized cost of our producing oil and natural gas properties to earnings

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through DD&A based on Boe units produced during the period as a percentage of total estimated Boe reserves. We also use reserve estimates, which may include (on a risk adjusted basis) reserves that are not proved reserves, to assess our productive oil and natural gas properties for impairment. Proved reserves are the estimated quantities of crude oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, estimated prices and costs as of the date the reserve estimates are made are held constant for the life of the reserves.

Independent reserve engineers prepare our oil and natural gas reserve estimates using guidelines established by the SEC and U.S. generally accepted accounting principles (GAAP). In December 2008, the SEC issued a final rule, Modernization of Oil and Gas Reporting, which amended its oil and gas reserves estimation and disclosure requirements. The new requirements were codified into ASC 932 in January 2010 and had the effect of, among other things: permitting the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; modifying the prices used to estimate reserves for SEC disclosure purposes to an average price based upon the prior twelve month period rather than the year-end price; and allowing the optional disclosure of probable and possible reserves to investors. The revised rule was effective January 1, 2010 for reporting December 31, 2009 annual oil and natural gas reserve information. We have adopted the provisions of the final rule in connection with the filing of this Annual Report. The quality and quantity of data, the interpretation of data, the accuracy of economic assumptions, and judgments and estimates regarding uncertain events and circumstances by us and our independent reserve engineers affect the accuracy of reserve estimates. We may materially revise our reserve estimates in subsequent periods due to drilling or production results or other data obtained after the date of the estimate.

As of December 31, 2009, proved oil and natural gas reserves were 31.2 Mmboe. Approximately 34% of our proved reserves is classified as proved developed producing reserves while 45% of our proved reserves is classified as proved developed non-producing reserves. Most of our proved developed non-producing reserves are classified as behind pipe and will be produced after depletion of another productive zone in the same well. Approximately 21% of total proved reserves are categorized as proved undeveloped reserves.

The present value of the future net cash flow disclosed in this Annual Report is not intended to reflect the market value of the oil and natural gas reserves. In accordance with ASC 932, we use prices based on the simple average of the closing price on the first day of each of the twelve months during the fiscal year, and costs determined on the date of the estimate held constant for the life of the reserves and a 10% discount rate to determine the present value of future net cash flow. Actual costs incurred and prices received in the future may vary significantly and the discount rate may not accurately reflect economic conditions.

As of December 31, 2009, the computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on prices of $3.96 per Mcf for natural gas and $57.70 per barrel for crude computed by applying the use of physical pricing based on the simple average of the closing price on the first day of each of the twelve months during the fiscal year (as required by ASC 932), applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price. These adjustments can vary significantly over time both in amount and as a percentage of the posted price, especially related to our oil prices during periods when the market price for oil varies widely. The price adjustments reflected in our computed reserve prices may not represent the amount of price adjustments we may actually obtain in the future when we sell our production. We estimated the costs based primarily on our actual historical costs incurred for appropriate periods of time for individual properties. Where a particular property does not have production during the year, we apply pricing adjustments based on the most similar property.

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Depletion, Depreciation and Amortization of Oil and Natural Gas Properties We calculate DD&A using the estimates of proved oil and natural gas reserves previously discussed in these critical accounting policies. We segregate the capitalized costs and record DD&A for capitalized property costs separately using the units-of-production method. The units-of- production method is based on the ratio of (1) actual volumes produced to (2) total proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods), or total proved reserves in the case of leasehold costs (the DD&A rate). Each period, this ratio is applied to the applicable capitalized asset cost category, resulting in allocation of the cost of our oil and natural gas properties over the periods during which they produce revenues. As previously discussed, material revisions to proved reserves may occur as a result of unforeseen factors and may materially impact the DD&A rate.

In 2009, we had negative revisions of 0.6 Mmboe, representing 2% of our total proved reserves of 36.8 Mmboe as of December 31, 2008. In 2008, we had negative revisions of 5.5 Mmboe, representing 12% of our total proved reserves of 45.3 Mmboe as of December 31, 2007. The negative revisions in 2008 resulted from a combination of price decreases in both oil and natural gas (3.5 Mmboe) and performance (2.0 Mmboe). Our past revisions have had minimal impact on our DD&A rates because they have been relatively low as a percentage of our reserve base and/or related to fields with little cumulative production. Historical revisions are not necessarily indicative of potential future revisions.

Impairment of Oil and Natural Gas Properties We evaluate our capitalized oil and natural gas property costs for potential impairment when circumstances indicate that the carrying value may not be recoverable. Because we accumulate capitalized costs separately, property by property (generally analogous to a field or a lease), for our proved oil and natural gas properties under the successful-efforts method of accounting, we perform impairment assessments on a property by property basis. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, or other changes to contracts or environmental regulations. In general, we do not view temporarily low oil or natural gas prices as a triggering event for conducting impairment tests. Historically, our sales price for oil and natural gas has varied significantly. Although our sales prices may rise and fall quickly over short periods of time, we believe sales prices over the long-term are primarily based on supply and demand factors. Accordingly, our impairment tests make use of long-term sales price assumptions for oil and natural gas. A significant amount of judgment and uncertainty is involved in performing impairment evaluations because major inputs to the computation are based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors.

Our assessment of possible impairment of proved oil and natural gas properties is based on our best estimate of future prices, costs and expected net future cash flows by property. An impairment loss is indicated if undiscounted net future cash flows are less than the carrying value of a property. The impairment expense is measured as the shortfall between the net book value of the property and its estimated fair value measured based on the discounted net future cash flows from the property. Actual prices, costs, and net future cash flows may vary from our estimates. Our discount rate may not accurately reflect economic conditions. We recognized impairment expense of $8.5 million, $8.1 million and $110.4 million in the period from October 1, 2009 through December 31, 2009, the period from January 1, 2009 through September 30, 2009 and the year ended December 31, 2008, respectively.

For individual unevaluated properties (those with no corresponding proved reserves) with capitalized cost below a threshold amount, we allocate capitalized costs to earnings generally over the primary lease terms. We believe this method provides a reasonable estimate of the amount of capitalized costs of unevaluated properties which will prove unproductive over the primary lease terms. Properties that are subject to amortization and those with capitalized costs greater than the threshold amount are assessed for impairment periodically. If we find oil and natural gas reserves sufficient to justify development of the property, we transfer the net capitalized cost of the unproved property to proved properties and DD&A is recorded on the units-of-production basis described above. If our efforts do not result in proved oil and natural gas reserves, the related net capitalized costs are charged to earnings as impairment expense.

Asset Retirement Obligations (AROs) We have material obligations to plug and abandon oil and natural gas wells and to decommission related platforms, pipelines and equipment as well as to dismantle and abandon facilities when they are no longer being used for the production of oil and natural gas. We record a liability for the estimated fair value of a material ARO in the period when we identify or incur the obligation. When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related asset, which is allocated to expense through DD&A on the units-of-production basis. Accretion increases the ARO liability over time, using the effective interest method.

Numerous estimates, assumptions and judgments are inherent in the calculation of ARO including ultimate settlement amounts, timing of settlements, technological changes, future inflation rates, the credit adjusted risk-free rate of interest, and changes in legal, regulatory, environmental and political environments. We revise our estimates of the fair value of ARO as information about material changes to the liability become known. Revisions are recorded as an adjustment to existing ARO liabilities and to the carrying amount of the related assets. Revisions occurring at or near the end of an asset s useful life may result in a material positive or negative impact on earnings.

Derivative Instruments and Hedging Activities We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Historically, our hedging instruments consisted primarily of financially-settled swaps and collars. We record our hedging instruments at fair market value as either assets or liabilities in our consolidated balance sheet. We estimate the fair value of hedging instruments based on estimated future commodity prices. The fair market value may differ from actual settlements if market prices change, the other party to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

Share-Based Compensation We measure compensation expense for all share-based payment awards based on their grant-date fair values. We use the Black-Scholes option pricing model to estimate fair values of share-based awards. Option pricing models, including the Black-Scholes model, require the use of input estimates and assumptions, including expected volatility, expected life, expected dividend rate, and expected risk-free rate of return. The assumptions for expected volatility and expected life most significantly affect the grant-date fair value. Our estimate of the forfeiture rate of our stock-based awards also impacts the amount of expense recorded over the expected life of the award. See Note 15, Employee Benefit Plans, in Part II, Item 8 of this Annual Report for a description of methods used to determine our assumptions. If we determined that another method used to estimate expected volatility or expected life was more reasonable than our current methods, or if another method for calculating these input assumptions was prescribed by authoritative guidance, the fair value calculated for share-based awards could change significantly. Higher volatility and longer expected lives result in increases to share-based compensation determined at the date of grant.

Deferred Tax Asset Valuation Allowance We are required to assess whether it is more likely than not that we will be able to realize some or all of our deferred tax assets. If we cannot determine that deferred tax assets are more likely than not recoverable, we are required to provide a valuation allowance against those assets. This assessment takes into account factors including: (a) the nature, frequency, and severity of current and cumulative financial reporting losses; (b) sources of estimated future taxable income; and (c) tax planning strategies. A pattern of recent financial reporting losses is heavily weighted as a source of negative evidence when determining the realizability of deferred tax assets. Projections of estimated future taxable income exclusive of reversing temporary differences are a source of positive evidence only when the projections are combined with a history of recent profitable operations and can be reasonably estimated. Otherwise, projections are considered inherently subjective and generally will not be sufficient to overcome negative evidence that includes cumulative losses in recent years. If necessary and available, tax planning strategies would be implemented to accelerate taxable amounts to utilize expiring carryforwards. These strategies would be a source of additional positive evidence supporting the realizability of deferred tax assets.

See Note 14 Income Taxes in Part II, Item 8 of this Annual Report for more information regarding our deferred taxes.

Changes in estimates and assumptions described in these critical accounting policies may result in material changes to our net income or loss from period to period.

New Accounting Pronouncements

For information regarding new accounting pronouncements, see the information in Note 18 New Accounting Pronouncements in the consolidated financial statements in Part II, Item 8 of this Annual Report.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view our ongoing market-risk exposure.

Interest Rate Risk

We are exposed to changes in interest rates which affect the interest earned on our interest-bearing deposits and the interest paid on borrowings under our Credit Facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At December 31, 2009, we had total indebtedness outstanding of $77.3 million (net of unamortized original issue discount of $5.9 million), of which $58.5 million, or approximately 76%, bears interest at fixed rates. The remaining $18.8 million of indebtedness bears interest at floating rates and consists of borrowings outstanding under the Credit Facility. At December 31, 2009, the weighted average interest rate under the Credit Facility was approximately 6.5%. If market interest rates were to average 1% higher in the first quarter of 2010, interest expense for the period on floating rate debt would be expected to increase by approximately $40,000.

Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

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Historically, we have used commodity derivative instruments to manage commodity price risks associated with future oil and natural gas production. As a result of our liquidity challenges that led to our filing for reorganization under Chapter 11, we had settled all of our outstanding derivative contracts during March and May of 2009. In compliance with requirements contained in the Credit Facility, we have entered into the following derivative instruments, which were outstanding as of December 31, 2009:

Oil Contracts

	Fixed-Price Swaps				Puts			
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Average Swap Price ($/Bbl)**	**Fair Value**	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Floor Price ($/Bbl)**	**Fair Value**
January 2010 July 2010	3,053	647,250	$ 67.34	$ (8,749,821)	502	106,500	$ 60.00	$ 93,363
August 2010 November 2010	625	76,200	$ 69.65	$ (1,011,766)	1,673	204,150	$ 60.00	$ 507,141
December 2010	1,200	37,200	$ 70.37	$ (494,097)	1,302	40,350	$ 60.00	$ 119,700
January 2011 July 2011	2,261	479,250	$ 71.13	$ (6,347,287)	502	106,500	$ 60.00	$ 384,093
August 2011 November 2011	502	61,200	$ 72.18	$ (795,908)	1,301	158,700	$ 60.00	$ 670,113
December 2011	948	29,400	$ 72.64	$ (376,067)	1,302	40,350	$ 60.00	$ 172,593

Natural Gas Contracts

	Puts			
Remaining Contract Term	**Daily Average Volume (Mmbtu)**	**Volume (Mmbtu)**	**Floor Price ($/Mmbtu)**	**Fair Value**
January 2010	24,000	744,000	$ 4.00	$
February 2010	25,000	700,000	$ 4.00	$ 3,205
March 2010	25,000	775,000	$ 4.00	$ 24,570
April 2010	25,000	750,000	$ 4.00	$ 53,608
May 2010	23,000	713,000	$ 4.00	$ 55,839
June 2010	22,000	660,000	$ 4.00	$ 56,441

All of our commodity derivative instruments are with one counterparty that is a lender under our Credit Facility.

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Item 8. ***Financial Statements and Supplementary Data***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Energy Partners, Ltd.:

We have audited Energy Partners, Ltd. s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Energy Partners, Ltd. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Energy Partners, Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Energy Partners, Ltd. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for the period from October 1, 2009 through December 31, 2009 (Successor Company), for the period from January 1, 2009 through September 30, 2009 (Predecessor Company), and the year ended December 31, 2008 (Predecessor Company), and our report dated March 10, 2010, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

New Orleans, Louisiana

March 10, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Energy Partners, Ltd.:

We have audited the accompanying consolidated balance sheets of Energy Partners, Ltd. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for the period from October 1, 2009 through December 31, 2009 (Successor Company), for the period from January 1, 2009 through September 30, 2009 (Predecessor Company), and the year ended December 31, 2008 (Predecessor Company). These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. 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 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 financial position of Energy Partners, Ltd. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for the period from October 1, 2009 through December 31, 2009 (Successor Company), for the period from January 1, 2009 through September 30, 2009 (Predecessor Company), and for the year ended December 31, 2008 (Predecessor Company), in conformity with U.S. generally accepted accounting principles.

As discussed in note 1 and note 3 to the consolidated financial statements, the Company filed a petition for reorganization under Chapter 11 of the United State Bankruptcy Code on May 1, 2009. The Company s plan of reorganization became effective, and the Company emerged from bankruptcy protection on September 21, 2009. In connection with its emergence from bankruptcy, the Successor Company Energy Partners, Ltd. and subsidiaries adopted fresh-start reporting in conformity with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 852 (ASC 852), *Reorganizations*. Accordingly, the Successor Company s consolidated financial statements prior to September 30, 2009 are not comparable to its consolidated financial statements for periods on or after September 30, 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Energy Partners, Ltd. s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 10, 2010 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ KPMG LLP

New Orleans, Louisiana

March 10, 2010

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2009 and 2008

(In thousands, except share data)

	SUCCESSOR COMPANY 2009	PREDESESSOR COMPANY 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 26,745	$ 1,991
Trade accounts receivable	27,958	29,264
Receivables from insurance	5,464	4,230
Fair value of commodity derivative instruments	914	5,415
Deferred tax assets	5,768	
Prepaid expenses	2,940	4,522
Total current assets	69,789	45,422
Property and equipment, under the successful efforts method of accounting for oil and natural gas properties	648,517	1,646,805
Less accumulated depreciation, depletion and amortization	(37,535)	(958,438)
Net property and equipment	610,982	688,367
Restricted cash	22,147	21,271
Other assets	3,647	3,350
Deferred financing costs net of accumulated amortization of $325 and $3,780 at December 31, 2009 and 2008, respectively	2,663	8,356
	$ 709,228	$ 766,766
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 14,047	$ 39,517
Accrued expenses	32,541	54,467
Accrued interest on indebtedness	281	9,506
Asset retirement obligations	10,830	18,181
Current portion of long-term debt	18,750	497,501
Fair value of commodity derivative instruments	10,256	28
Deferred tax liabilities		1,580
Total current liabilities	86,705	620,780
Long-term debt	58,590	
Asset retirement obligations	59,150	87,506
Deferred tax liabilities	16,953	
Fair value of commodity derivative instruments	7,519	55
Other	224	1,306
Commitments and contingencies		
	229,141	709,647
Stockholders equity:		

Preferred stock: Successor Company $0.001 par value per share; authorized 1,000,000 shares; no shares issued and outstanding at December 31, 2009. Predecessor Company $1 par value per share; authorized 1,700,000 shares; no shares issued and outstanding at December 31, 2008		
Successor Company Common stock, par value $0.001 per share; authorized 75,000,000 shares; issued and outstanding: 40,021,770 shares at December 31, 2009	40	
Predecessor Company Common stock, par value $0.01 per share; authorized 100,000,000 shares; 44,323,293 shares issued at December 31, 2008; 32,083,307 outstanding, net of treasury shares, at December 31, 2008		444
Additional paid-in capital	501,059	382,232
Accumulated deficit	(21,012)	(67,201)
Treasury stock, at cost, 12,239,986 shares at December 31, 2008		(258,356)
Total stockholders equity	480,087	57,119
	$ 709,228	$ 766,766

See accompanying notes to consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Period from October 1, 2009 through December 31, 2009 and for the Period from January 1, 2009 through September 30, 2009 and the Year Ended December 31, 2008

(In thousands, except per share data)

	SUCCESSOR COMPANY	PREDECESSOR COMPANY	
	Period from October 1, 2009 through December 31, 2009	Period from January 1, 2009 through September 30, 2009	Year Ended December 31, 2008
Revenue:			
Oil and natural gas	$ 56,708	$ 134,583	$ 356,022
Other	42	302	230
	56,750	134,885	356,252
Costs and expenses:			
Lease operating	13,410	46,296	71,931
Transportation	315	699	1,089
Exploration expenditures and dry hole costs	453	1,650	30,199
Impairments	8,514	8,082	110,403
Depreciation, depletion and amortization	28,448	95,944	103,318
Accretion of liability for asset retirement obligations	3,024	5,536	4,370
General and administrative	4,537	19,493	37,308
Taxes, other than on earnings	2,083	5,987	11,245
Gain on sale of assets			(5,527)
Loss on abandonment activities	493	3,732	21,695
Other	(4)	(26)	
Total costs and expenses	61,273	187,393	386,031
Business interruption recovery		1,185	4,248
Loss from operations	(4,523)	(51,323)	(25,531)
Other income (expense):			
Interest income	3	47	784
Interest expense (contractual interest of $34,076 for the period from January 1, 2009 through September 30, 2009)	(4,322)	(17,813)	(46,533)
Gain (loss) on derivative instruments	(22,705)	2,728	2,053
	(27,024)	(15,038)	(43,696)
Loss before reorganization items, loss on discharge of debt, fresh-start adjustments and income taxes	(31,547)	(66,361)	(69,227)
Reorganization items (Note 4)	(865)	(24,198)	
Loss on discharge of debt (Note 3)		(2,666)	
Fresh-start adjustments (Note 3)		57,111	

Loss before income taxes	(32,412)	(36,114)	(69,227)
Income tax benefit	11,400		17,015
Net loss	(21,012)	(36,114)	(52,212)
Basic and diluted loss per share	$ (0.53)	$ (1.12)	$ (1.63)
Weighted average common shares used in computing earnings per share:			
Basic and diluted	40,020	32,200	31,988

See accompanying notes to consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

For the Period from October 1, 2009 through December 31, 2009 and for the Period from January 1, 2009 through September 30, 2009 and the

Year Ended December 31, 2008

(In thousands)

	Treasury Stock Shares	Treasury Stock	Predecessor Company Common Stock Shares	Predecessor Company Common Stock	Successor Company Common Stock Shares	Successor Company Common Stock	Additional Paid In Capital	Accumulated Other Comprehensive Loss	Retained Earnings (Deficit)	Total
Balance, December 31, 2007 Successor Company	12,240	$ (258,356)	43,981	$ 441		$	$ 374,874	$	$ (14,989)	$ 101,970
Stock purchase, compensation and incentive plans, net			116	1			4,789			4,790
Exercise of common stock options			79	1			749			750
Comprehensive loss:										
Net loss									(52,212)	(52,212)
Comprehensive loss										(52,212)
Other			147	1			1,820			1,821
Balance, December 31, 2008 Predecessor Company	12,240	(258,356)	44,323	444			382,232		(67,201)	57,119
Stock purchase, compensation and incentive plans, net			297	2			3,420			3,422
Comprehensive loss:										
Net loss									(36,114)	(36,114)
Comprehensive loss										(36,114)
Other			54	1			616			617
Reorganization Adjustments	(12,240)	258,356	(44,674)	(447)	40,000	40	114,566		103,315	475,830
Stock issued to Directors pursuant to 2009 LTIP					18					
Balance, September 30, 2009 Successor Company		$		$	40,018	$ 40	$ 500,834	$	$	$ 500,874
Stock compensation and incentive plan awards pursuant to 2009 LTIP							243			243

Comprehensive loss:								
Net loss							(21,012)	(21,012)
Comprehensive loss								(21,012)
Other			4		(18)			(18)
Balance, December 31, 2009 Successor Company	$	$	40,022	$ 40	$ 501,059	$	$ (21,012)	$ 480,087

See accompanying notes to consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Period from October 1, 2009 through December 31, 2009 and for the Period from January 1, 2009 through September 30, 2009 and the Year Ended December 31, 2008

(In thousands)

	SUCCESSOR COMPANY	PREDECESSOR COMPANY	
	Period from October 1, 2009 through December 31, 2009	Period from January 1, 2009 through September 30, 2009	Year Ended December 31, 2008
Cash flows from operating activities:			
Net loss	$ (21,012)	$ (36,114)	$ (52,212)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	28,448	95,944	103,318
Accretion of liability for asset retirement obligations	3,024	5,536	4,370
Loss on discharge of debt		2,666	
Fresh-start adjustments		(57,111)	
Unrealized (gain) loss on derivative contracts	21,739		(19,058)
Non cash compensation	417	3,689	6,108
In-kind interest on PIK Notes	3,395		
Deferred income taxes	(11,400)		(17,015)
Gain on disposal of assets and other			(5,827)
Exploration expenditures	163	126	21,796
Impairments	8,514	8,082	110,403
Amortization of deferred financing costs and discount on debt	524	8,356	1,834
Loss on abandonment activities	493	3,732	21,695
Other		3	879
Changes in operating assets and liabilities:			
Trade accounts receivable	(3,501)	4,807	21,655
Other receivables	(1,428)	194	(4,249)
Prepaid expenses	1,505	677	2,276
Other assets	(1,570)	(641)	(5,819)
Accounts payable and accrued expenses	(10,806)	(2,414)	22,045
Asset retirement obligations	(1,637)	(22,374)	(26,915)
Other liabilities		(792)	(674)
Net cash provided by operating activities	16,868	14,366	184,610
Cash flows used in investing activities:			
Property acquisitions	(54)	(31)	(20,925)
Exploration and development expenditures	(2,731)	(29,723)	(199,157)
Other property and equipment additions	(23)	(147)	(724)
Proceeds from sale of oil and gas assets		150	15,576
Net cash used in investing activities	(2,808)	(29,751)	(205,230)
Cash flows provided by (used in) financing activities:			
Deferred financing costs		(798)	(5)
Repayments of indebtedness	(31,250)	(55,001)	(120,000)

Proceeds from indebtedness		113,128	133,000
Exercise of stock options and warrants			752
Net cash provided by (used in) financing	(31,250)	57,329	13,747
Net increase (decrease) in cash and cash equivalents	(17,190)	41,944	(6,873)
Cash and cash equivalents at beginning of period	43,935	1,991	8,864
Cash and cash equivalents at end of year	$ 26,745	$ 43,935	$ 1,991
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Non-cash financing information:			
Discharge of Senior Unsecured Notes, including accrued interest of $18,663		$ 473,164	
Issuance of equity in Successor Company		500,874	
Debt incurred to repay secured bank credit facility, including accrued interest of $1,085		29,084	
Debt incurred to pay deferred financing costs and surety bond premium		2,790	
Debt incurred to pay interest on PIK Notes	3,395		
Cash paid during the period for:			
Interest	552	5,614	46,875
Income taxes			

See accompanying notes to consolidated financial statements.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization

The Company was incorporated as a Delaware corporation on January 29, 1998. We operate as an independent oil and natural gas exploration and production company. Our current operations are concentrated in the shallow to moderate depth waters in the Gulf of Mexico focusing on the areas of offshore Louisiana as well as the deepwater Gulf of Mexico in depths less than 5,000 feet.

On May 1, 2009 (the Petition Date), we and certain of our subsidiaries filed voluntary petitions (In re: Energy Partners, Ltd., et. al., Case No. 09-32957) for reorganization under Chapter 11 of Title 11 of the United States Code, 11 U.S.C. §§ 101 et seq., as amended (Chapter 11), in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (the Bankruptcy Court).

We continued to manage our properties and operate our business as debtors-in-possession while under the jurisdiction of the Bankruptcy Court. On September 21, 2009, we emerged from Chapter 11 reorganization (the Exit Date) pursuant to the plan of reorganization confirmed by the Bankruptcy Court (the Plan). On the Exit Date, we consummated certain transactions contemplated by the Plan, including entering into a senior secured credit facility consisting of a $125 million revolving credit facility with an initial borrowing base of $45 million (the Revolver) and a $25 million one-year amortizing term loan facility (together with the Revolver, the Credit Facility). We also issued 20% Senior Subordinated Secured PIK Notes due 2014 in an aggregate principal amount of $61.1 million (the PIK Notes). The PIK Notes were issued with original issue discount, and the note proceeds after this discount were $55.0 million. As of September 28, 2009, we had satisfied the hedging requirements under the Credit Facility and had delivered to the Minerals Management Service (the MMS) the financial support related to abandonment obligations on certain federal leases in the Gulf of Mexico. The Chapter 11 filings and related matters are addressed in Note 3, Reorganization and Fresh-Start Accounting.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (GAAP) and include the accounts of Energy Partners, Ltd. and our wholly-owned subsidiaries. All significant intercompany accounts and transactions are eliminated in consolidation. Our interests in oil and natural gas exploration and production ventures and partnerships are proportionately consolidated.

The financial statements for the period in which the Company was in reorganization under Chapter 11 were prepared in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 852 (ASC 852), Reorganizations, (originally issued as the American Institute of Certified Public Accountant s Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code). Under ASC 852, we must, among other things, (1) identify transactions that are directly associated with the reorganization from those events that occur during the normal course of business, (2) identify pre-petition liabilities subject to compromise from those that are not subject to compromise or are post petition liabilities and (3) apply fresh-start accounting rules upon emergence from Chapter 11 reorganization (see Note 3). In accordance with the Plan, only the Company s 9.75% Senior Unsecured Notes due 2014 (the Fixed Rate Notes), its Senior Floating Rate Notes due 2013 (the Floating Rate Notes and together with the Fixed Rate Notes, the Senior Unsecured Notes) and its 8.75% Senior Notes due 2010 (collectively with the Senior Unsecured Notes, the Predecessor Company Notes) and the related accrued interest were discharged in the reorganization. As a result, we discontinued accruing interest on the Predecessor Company Notes as of the Petition Date.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In accordance with Topic 852, we adopted fresh-start accounting as of September 30, 2009. Fresh-start accounting is required upon a substantive change in control and requires that the reporting entity allocate the reorganization value of the Company to its assets and liabilities in relation to their fair values. Under the provisions of fresh-start accounting, a new entity has been deemed created for financial reporting purposes. References to the Predecessor Company refer to reporting dates of the Company through September 30, 2009, including the effect of the reorganization and application of fresh-start accounting; subsequent thereto, the Company is referred to as the Successor Company in the consolidated financial statements and the notes thereto. The financial statements for the year ended December 31, 2008 do not reflect the effect of any changes in the Company s capital structure or changes in fair values of assets and liabilities as a result of fresh-start accounting. For further information on fresh-start accounting, see Note 3.

(b) Property and Equipment

We use the successful efforts method of accounting for oil and natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. We may capitalize exploratory well costs beyond one year if (a) we found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project; otherwise, these costs are expensed. Geological and geophysical costs are charged to expense as incurred.

Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold costs are transferred to proved properties. For individual unevaluated properties with capitalized cost below a threshold amount, we allocate capitalized costs to earnings generally over the primary lease terms. Properties that are subject to amortization and those with capitalized costs greater than the threshold amount are assessed for impairment periodically. Capitalized costs of producing oil and natural gas properties are depreciated and depleted by the units-of-production method.

We evaluate our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicate that the carrying values may not be recoverable. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, or other changes to contracts, environmental regulations or tax laws. The calculation is performed on a field-by-field basis, utilizing our current estimates of future revenues and operating expenses. In the event net undiscounted cash flow is less than the carrying value, an impairment loss is recorded based on the present value of expected future net cash flows over the economic lives of the reserves.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion, depreciation and amortization are eliminated from the property accounts, along with the related asset retirement obligations, unless retained by us, and the resulting gain or loss is recognized in earnings.

(c) Asset Retirement Obligations

We record our obligations associated with the retirement of tangible long-lived assets at their fair values in the period incurred. The fair value of the obligation is also recorded to the related asset s carrying amount. Accretion of the liability is recognized as an operating expense and the capitalized cost is amortized using the units-of-production method. Our asset retirement obligations relate primarily to the plugging and abandonment of our oil and natural gas wellbores and to decommissioning related pipelines, facilities and structures.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(d) Income Taxes

We account for income taxes under the asset and liability method, which requires that we recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis amounts. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. We recognize the effect on deferred tax assets and liabilities of a change in the tax rates in income in the period that includes the enactment date.

We follow the provisions of ASC Topic 740, Income Taxes, which apply to the accounting for uncertainty in income taxes recognized in an enterprise s financial statements and prescribe a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. These provisions also contain guidance on de-recognition, classification, interest and penalties. Interest, if any, is classified as a component of interest expense, and statutory penalties, if any, are classified as a component of general and administrative expense.

(e) Deferred Financing Costs

We defer costs incurred to obtain debt financing and then amortize such costs as additional interest expense over the maturity period of the related debt.

(f) Earnings Per Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed in the same manner as basic earnings per share except that the denominator is increased to include the number of additional common shares that could have been outstanding assuming the exercise of stock option awards and warrants and the potential shares associated with restricted share units and performance shares that would have a dilutive effect on earnings per share.

(g) Revenue Recognition

We record revenues from the sales of oil and natural gas when the product is delivered at a determinable price, title has transferred and collectability is reasonably assured. When we have an interest with other producers in properties from which natural gas is produced, we use the entitlement method for recording natural gas sales revenue. Under this method of accounting, revenue is recorded based on our net revenue interest in production. Deliveries of natural gas in excess of our revenue interest are recorded as liabilities and under-deliveries are recorded as receivables. We had natural gas imbalance receivables of $0.1 million at December 31, 2008, and had liabilities of $2.5 million and $2.3 million at December 31, 2009 and 2008, respectively.

(h) Cash and Cash Equivalents

We include in cash and cash equivalents our highly-liquid investments with original maturities of three months or less. At December 31, 2009 and 2008, cash and cash equivalents includes investments in overnight interest-bearing deposits of $27.2 million and $4.1 million, respectively. These amounts are reduced by overdraft balances on other operating accounts with legal right of offset in the same banking institution to arrive at the cash and cash equivalent balances reported in our consolidated balance sheets.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(i) Derivative Activities

Derivative instruments, including certain derivative instruments embedded in other contracts, are recorded at fair market value and included as either assets or liabilities in the balance sheet. The accounting for changes in fair value depends on the intended use of the derivative and the resulting designation, which is established at the inception of the derivative. We do not elect to designate derivative instruments as hedges. Unrealized gains and losses resulting from changes in the fair value of derivative instruments are recorded in other income (expense). Realized gains and losses related to contract settlements are also recognized in other income (expense).

(j) Stock-Based Compensation

We recognize stock-based compensation expense based on the estimated grant-date fair value of all stock-based awards, net of an estimated forfeiture rate, over the requisite service period of the awards, which is generally equivalent to the vesting term. We record stock-based compensation expense only for those awards expected to vest. We periodically revise our estimated forfeiture rate if actual forfeitures differ from our estimates.

We are required to report excess tax benefits from the exercise of stock options as financing cash flows. No stock options were exercised during 2009. For the year ended December 31, 2008, no excess tax benefits were reported in the statement of cash flows as we are in a net operating loss carryforward position. See Note 15 for additional disclosures.

(k) Allowance for Doubtful Accounts

We routinely assess the recoverability of all material trade and other receivables to determine their collectability. Our crude oil and natural gas revenue receivables are typically collected within two months. We may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest receivables on properties where we are the operator. When we believe collection of the full amount of our accounts receivable is in doubt, we record an allowance to reflect accounts receivable at the net realizable value, which may be reflected in earnings or as an increase to the net book value of our oil and natural gas properties depending on the nature of the transaction that created the receivable. The nature of the transaction resulting in the receivable balance determines whether the allowance, when recorded, impacts our earnings (ordinarily through LOE) or our property and equipment balances. As of December 31, 2009, our allowance for doubtful accounts was $2.0 million, of which $0.1 million and $0.8 million was recorded as a reduction in earnings in the periods from October 1, 2009 through December 31, 2009 and January 1, 2009 through September 31, 2009, respectively. As of December 31, 2008 our allowance for doubtful accounts was $1.1 million, $0.9 million of which was recorded as a reduction in earnings in 2008.

(l) Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We use historical experience and various other assumptions that are believed to be reasonable under the circumstances to form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. Our actual results may differ from these estimates and assumptions used in preparation of our

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

financial statements. Significant estimates with regard to these financial statements and related unaudited disclosures include the estimated fair values of assets and liabilities used in the application of fresh-start accounting as described in Note 3 and the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows therefrom disclosed in Note 19.

(m) Reclassifications

Certain reclassifications have been made to the prior period financial statements in order to conform to the classification adopted for the most recent reporting period. Specifically, we have reported the cost of certain insurance coverages applicable to proved properties and wells and related equipment and facilities in lease operating expenses in the consolidated statement of operations for all periods reported. We previously reported the cost of these insurance coverages in general and administrative expenses.

(3) Reorganization and Fresh-Start Accounting

We reflected the reorganization and application of ASC 852 as of September 30, 2009. Fresh-start accounting is required upon a substantive change in control and requires that the reporting entity allocate the reorganization value of the Successor Company to its assets and liabilities in relation to their fair values. Based on financial projections that we and our advisors developed, the allocation of the reorganization value was determined using various valuation methods, including (i) comparable company analysis, which estimates the value of the Company based on the implied valuations of other similar companies; (ii) comparable asset transaction analysis, which estimates the value of a company based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of a company based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis, which estimates the value of the Company by determining the present value of estimated future cash flows. The reorganization value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties and contingencies which are beyond our control. The fair value allocated to our property and equipment should not be viewed as representative of the current value of our oil and natural gas reserves or the current value of the Company. The reorganization value of the Company was estimated to be approximately $603 million.

In order to reflect the reorganization and application of ASC 852, we adjusted the book values of the Predecessor Company s assets and liabilities to reflect the estimated fair values of the Successor Company s assets and liabilities, on a net basis. These adjustments increased net income by $57.1 million. The restructuring of the Company s capital (see Note 5) and resulting discharge of the Predecessor Company Notes and related accrued interest resulted in a loss of $2.7 million. The adjustments for the revaluation of the assets and liabilities and the loss on the discharge of pre-petition debt are recorded in Fresh-start adjustments and Loss on discharge of debt, respectively, in the condensed consolidated statement of operations.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reflects the reorganization and application of ASC 852 on our condensed consolidated balance sheet as of September 30, 2009:

(In thousands)	Predecessor Company as of September 30, 2009	Reorganization Adjustments (1)	Fresh-Start Adjustments (2)	Successor Company as of September 30, 2009
ASSETS				
Current assets:				
Cash and cash equivalents	$ 43,935	$	$	$ 43,935
Trade accounts receivable	24,457			24,457
Receivables from insurance	4,036			4,036
Fair value of commodity derivative instruments		2,379		2,379
Prepaid expenses	4,445			4,445
Total current assets	76,873	2,379		79,252
Property and equipment	1,645,651		(1,026,377)	619,274
Less accumulated depreciation, depletion and amortization	(1,057,701)		1,057,701	
Net property and equipment	587,950		31,324	619,274
Restricted cash	22,148			22,148
Other assets	1,712	2,863		4,575
Deferred financing costs		2,988		2,988
	$ 688,683	$ 8,230	$ 31,324	$ 728,237
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable	$ 23,487	$ (6,320)	$	$ 17,167
Accrued expenses	43,739	(6,366)		37,373
Accrued interest on indebtedness	1,516	(1,085)		431
Asset retirement obligations	9,308			9,308
Secured bank credit facility	83,000	(83,000)		
Secured bank credit facility term loan		25,000		25,000
Total current liabilities	161,050	(71,771)		89,279
Liabilities subject to compromise:				
Senior unsecured debt	454,501	(454,501)		
Accrued interest on senior unsecured debt	18,663	(18,663)		
Long-term debt		80,001		80,001
Asset retirement obligations	83,679		(25,787)	57,892
Other liabilities	191			191
	718,084	(464,934)	(25,787)	227,363
Stockholders equity:				
Preferred stock				
Common stock	447	(407)		40

Additional paid-in capital	386,268	114,566		500,834
Accumulated deficit	(157,760)	100,649	57,111	
Treasury stock	(258,356)	258,356		
Total stockholders equity	(29,401)	473,164	57,111	500,874
	$ 688,683	$ 8,230	$ 31,324	$ 728,237

(1) To record the discharge of liabilities subject to compromise, the conversion of the Predecessor Company s common stock into new common stock of the Successor Company and to reduce the Predecessor Company s accumulated deficit to zero. This column also reflects the following:

payment of pre-petition vendor claims totaling $6.3 million;

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

premiums of $5.2 million associated with hedging requirements under the Credit Facility;

payment of Predecessor Company secured bank credit facility and related accrued interest;

payments totaling approximately $9.4 million for financing costs and certain reorganization items; and

loss on discharge of debt of $2.7 million reflected in accumulated deficit.

(2) To adjust assets and liabilities to fair values.
The fair value assigned to our proved oil and natural gas properties as of September 30, 2009 was estimated by adjusting the pre-tax future cash flows from our proved reserves as set forth in our reserve reports prepared by our independent reservoir engineers as of December 31, 2008 to reflect the production for the period from December 31, 2008 through September 30, 2009 and to reflect other revisions of reserve quantities identified during 2009, which revisions were not significant. We used the NYMEX forward price curve of oil and natural gas as of September 30, 2009 to estimate the future selling price of our reserves, which we escalated at a 2.5% inflation rate for periods beyond the limits of the NYMEX forward price curve. The weighted average prices of oil and natural gas reflected in our estimate of the fair value of proved reserves were $83.88 per barrel of oil and $6.98 per mcf of natural gas. Proved reserve volumes were risk-adjusted by reference to the Society of Petroleum Engineers 28th Annual Survey of Economic Parameters (June 2009) (SPEE Survey) based on the reserve category as follows: (i) proved developed producing 100%; (ii) proved non-producing 80%; (iii) proved behind pipe 80%; (iv) proved undeveloped 65%. Probable and possible reserves were risk-adjusted at 35% and 10%, respectively, by reference to the SPEE Survey. Estimated income taxes were deducted from future cash flows at a rate of 8.6%, which reflects the estimated rate of payment of cash taxes with reference to comparable companies. Net estimated future cash flows after estimated operating costs were discounted at 14.4% per year by reference to the SPEE Survey.

Our asset retirement obligations changed as a result of the application of ASC 852 because the discount rate and inflation rate applied to the estimated future abandonment costs in order to determine the fair value as of September 30, 2009 differed from the discount rates and inflation rates used to establish asset retirement obligations in prior periods under ASC Topic 410, Asset Retirement and Environmental Obligations (originally issued as Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations).

(4) Reorganization Items

Under ASC 852, certain costs and income items resulting from the reorganization and restructuring of the business are reported separately as reorganization items classified as non-operating expenses. Our reorganization items were as follows:

(In thousands)	Successor Company Period from October 1, 2009 through December 31, 2009	Predecessor Company Period from January 1, 2009 through September 30, 2009
Amortization of deferred financing costs	$	$ 6,838
Professional fees	785	14,462
Directors and officers insurance premium		1,573
Provision for rejected/renegotiated contracts	80	1,300
Employee agreements		25

Total reorganization items	$ 865	$ 24,198

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred financing costs as of the Petition Date associated with the Predecessor Company Notes were written off in accordance with the provisions of ASC 852. We also wrote off the remaining balance of deferred financing costs associated with the Predecessor Company s bank credit facility which was repaid in connection with our emergence from Chapter 11 reorganization.

We retained advisors to assist in our reorganization under Chapter 11 and incurred significant costs associated with the restructuring. Professional fees primarily relate to fees paid to our financial and legal advisors, the advisors to our creditors that we were obligated to pay under certain agreements and the advisors to the official committees appointed during our Chapter 11 proceedings. During the nine months ended September 30, 2009, we made cash payments for these professional fees, including retainers, totaling approximately $9.0 million which are included in our cash flows from operating activities for the period. In addition to monthly fees, as of September 30, 2009, we had accrued a success fee of $3.4 million that we were obligated to pay to our financial advisor under our agreement with that firm, which is included in professional fees in the table above. This fee was paid during the period from October 1, 2009 through December 31, 2009.

Prior to our filing for reorganization under Chapter 11, we purchased a six-year extension to our directors and officers insurance coverage (commonly referred to as a tail policy). The premium amount of $1.6 million was recorded and paid in cash during the nine months ended September 30, 2009.

During September, 2009, with the approval of the Bankruptcy Court, we renegotiated the lease for our corporate office in Louisiana and rejected the lease for our office in Texas and recorded $1.4 million in associated costs, $0.9 million of which was paid during the period from October 1, 2009 through December 31, 2009. Approximately $0.5 million was paid in 2010, representing the final payment due on our lease renegotiations.

In June 2009, we executed retention agreements with all of our non-officer, non-field employees, which called for payments of one-half of the retention amounts upon execution of the agreements and the remaining one-half upon exit from our Chapter 11 reorganization. Our field employees also received payments under this program. We also executed agreements with all of our officers (except for two executive officers who had individual change of control severance agreements with the Company) that called for payments of the entire retention amount upon exit from our Chapter 11 reorganization. During the period from January 1, 2009 through September 30, 2009, we recorded approximately $2.0 million for cash payments under these agreements. In addition, the remaining two executive officers terminated their written change of control severance agreements with the Company in exchange for receiving an unsecured claim for rejection damages in the Chapter 11 reorganization. In connection with these retention agreements, non-field employees and officers were required to waive and release the Company from any and all potential claims with respect to certain incentive and retention plans and agreements as provided for in the retention agreements. During the period from January 1, 2009 through September 30, 2009, we reduced previously established accruals totaling approximately $2.0 million for the various incentive and retention plans and agreements that were waived and released.

(5) Common Stock

In connection with our emergence from Chapter 11 reorganization, we converted the Predecessor Company Notes and outstanding Predecessor Company common stock into shares of our new common stock as of the Exit Date. In accordance with the terms of the Plan, the Predecessor Company Notes and related indentures, as well as the Predecessor Company s outstanding common shares, were cancelled. Each holder of these notes received, in exchange for such holder s respective claim (including principal and accrued interest), such holder s pro rata portion of approximately 95% of the common stock in the Successor Company, or 38 million shares. Each holder of the Predecessor Company s common stock received, in full satisfaction of and in exchange for such holder s

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

respective common stock interests, such holder s pro rata portion of approximately 5% of the common stock in the Successor Company, or approximately 2 million shares. The shares of treasury stock held by the Predecessor Company were not allocated any portion of the newly issued common stock. In each case, the common stock of the Successor Company issued pursuant to the Plan is subject to dilution by the issuance of shares of common stock issuable under the Successor Company s 2009 Long-Term Incentive Plan. We have reserved up to 1,237,000 shares of common stock for the issuance of restricted shares and option shares under the 2009 Long-Term Incentive Plan. See Note 15, Employee Benefit Plans for information regarding the 2009 Long-Term Incentive Plan.

Covenants in the Credit Facility and the indenture related to our PIK Notes place certain restrictions and conditions on our ability to pay dividends on our common stock.

(6) Mergers, Acquisitions and Dispositions

In March 2008, we completed the sale of two Gulf of Mexico Shelf properties located in our Western offshore area for $15.0 million after giving effect to preliminary closing adjustments. We recorded a gain on the sale of $7.1 million.

(7) Property and Equipment

The following is a summary of property and equipment at December 31, 2009 and 2008:

	Successor Company 2009		Predecessor Company 2008
		(In thousands)	
Proved oil and natural gas properties	$ 618,508	$	1,601,748
Unproved oil and natural gas properties	28,606		36,274
Other	1,403		8,783
	$ 648,517	$	1,646,805

Substantially all of our oil and natural gas properties serve as collateral under our Credit Facility and the PIK Notes.

We recognized impairment expense of $8.5 million, $8.1 million, and $110.4 million in the period from October 1, 2009 through December 31, 2009, the period from January 1, 2009 through September 30, 2009, and the year ending December 31, 2008, respectively.

Impairment expense for the period from January 1, 2009 through September 30, 2009 was primarily related to two producing fields which were determined to have future net cash flows less than their carrying values due to commodity price declines and reservoir performance. Impairment expense recorded by the Successor Company in the quarter ended December 31, 2009 is primarily related to two wells in our Western offshore area, one of which was unsuccessfully recompleted in 2010; the other was determined to be mechanically unable to produce a behind-pipe reservoir.

During 2008, we recorded impairments of oil and natural gas properties totaling $110.4 million. The impairment expense was primarily related to certain deepwater prospects ($47.5 million), producing fields

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(primarily five) which were determined to have future net cash flows less than their carrying values due primarily to commodity price declines and reservoir performance resulting in the write down of these properties to their estimated fair values as of December 31, 2008 ($39.3 million) and certain undeveloped properties ($20.8 million).

We capitalize exploratory well costs until we determine that the well has found proved reserves or is deemed noncommercial, in which case the well costs are charged to exploration expense. Changes in exploratory well costs that were capitalized for a period of greater than one year, excluding amounts that were capitalized and subsequently expensed in the same period, are as follows:

	Year Ended December 31, 2008 (In thousands)
Capitalized exploratory well costs, beginning of period	$ 32,612
Additions to capitalized exploratory well costs pending determination of proved reserves	
Capitalized exploratory well costs charged to expense	(32,612)
Capitalized exploratory well costs, end of period	$

At December 31, 2009 and 2008, we did not have any projects that were suspended for a period greater than one year.

(8) Tropical Weather

In late August and early September 2008 Hurricanes Gustav and Ike traversed the Gulf of Mexico and adjacent land areas. As a result of these two hurricanes, nearly all of our production was shut-in at one time or another during the third and fourth quarters of 2008. For these occurrences, we previously maintained business interruption insurance on a portion of our lost revenue on our South Timbalier 41, 42 and 46 properties. Recovery of lost revenue from these properties began accruing during the fourth quarter of 2008 when the no claim period provided for under the policy elapsed. Through December 31, 2008, the total business interruption claim on these fields was $4.2 million, all of which was recorded in other receivables at December 31, 2008. All of these amounts were collected in 2009. During the periods from October 1, 2009 through December 31, 2009 and from January 1, 2009 through September 30, 2009, we recorded reductions to lease operating expenses for property damage claims totaling approximately $4.1 million and $1.4 million, respectively, all of which is recorded in receivables from insurance at December 31, 2009. In order to mitigate the higher cost of insurance coverages in 2009, we negotiated higher deductibles for property damage due to windstorms (such as hurricanes) with a deductible of $20 million per occurrence and significantly lower aggregates for property damage due to windstorms with an aggregate annual limit of $55 million. Due to limited availability of insurance coverage at commercially acceptable rates, we no longer maintain business interruption insurance.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(9) Asset Retirement Obligations

We record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred, along with a corresponding increase in the carrying amount of the related long-lived asset. The following table reconciles the beginning and ending aggregate recorded amount of our asset retirement obligations:

	Successor Company	Predecessor Company	
	Period from October 1, 2009 through December 31, 2009	Period from January 1, 2009 through September 30, 2009	Year Ended December 31, 2008
		(in thousands)	
Beginning of period total	$ 67,200	$ 105,687	$ 77,898
Accretion expense	3,024	5,536	4,370
Sale of properties			(1,821)
Revisions	1,384	3,765	36,444
Liabilities incurred			13,385
Liabilities settled	(1,628)	(22,001)	(24,589)
End of period total	69,980	92,987	105,687
Less: End of period current portion	(10,830)	(9,308)	(18,181)
End of the period noncurrent portion	$ 59,150	$ 83,679	$ 87,506

Our asset retirement obligations were reduced by approximately $25.8 million as a result of the application of ASC 852 because the discount rate and inflation rate applied to the estimated future abandonment costs in order to determine the fair value as of September 30, 2009 differed from the discount rates and inflation rates used to establish asset retirement obligations in prior periods.

During 2008, we began to plug and abandon a significant number of wellbores and began decommissioning associated with platforms, structures, pipelines and facilities on leases in the Gulf of Mexico that are no longer producing and were required, in most instances, to be performed during that period under MMS requirements. The level of abandonment activity we performed in 2008 was significantly higher than in any past period and was performed at a high pricing point in the market for such services with equipment, in some cases, that exceeded the capability of less costly equipment capable of performing such operations. Further, because we performed this work at a suboptimal time of the year, we were significantly impacted by weather delays. We experienced costs significantly in excess of our recorded ARO for this work. As a result of this experience, and our cost experience on other 2008 abandonment activities, as well as our efforts to estimate our planned work for 2009, we revised our estimated abandonment costs where appropriate to reflect recent experience in determining the estimated fair value of our abandonment obligations at December 31, 2008. The total impact on earnings of our revisions to ARO for 2008 was a loss on abandonment of $21.7 million. Revisions to ARO that did not result in an impact to 2008 earnings were recorded as additions to our oil and natural gas properties and are amortized over remaining units-of-production.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) Indebtedness

Total indebtedness was as follows:

(In thousands)	SUCCESSOR COMPANY December 31, 2009	PREDECESSOR COMPANY December 31, 2008
Term loan component of Credit Facility, interest rate of 6.5% on December 31, 2009 based on base rate plus a floating spread, payable September 21, 2010	$ 18,750	$
Revolving credit component of Credit Facility, interest rate of 6.5% on December 31, 2009 based on LIBOR plus a floating spread, payable September 21, 2012		
PIK Notes, face amount of $61.1 million, interest rate of 20%, payable September 21, 2014 (net of $5.9 million of unamortized original issue discount)	55,195	
In-kind interest on PIK Notes (new notes issued January 1, 2010), face amount of $3.4 million, interest rate of 20%, payable September 21, 2014	3,395	
Fixed Rate Notes, interest rate of 9.75%, payable May 15, 2014		300,000
Floating Rate Notes, with weighted average interest of 9.94% on December 31, 2008, payable April 15, 2013		150,000
Senior Notes, annual interest of 8.75%, payable August 1, 2010		4,501
Pre-Reorganization Credit Agreement, interest rate based on LIBOR borrowing rates plus a floating spread payable April 23, 2011, with weighted average interest on December 31, 2008 of 2.57%		43,000
Total indebtedness	77,340	497,501
Current portion of indebtedness	18,750	497,501
Noncurrent portion of indebtedness	$ 58,590	$

Credit Facility

On September 21, 2009, we entered into the Credit Facility with General Electric Capital Corporation, as administrative agent (the Agent) and the lender parties thereto (the Lenders). The Credit Facility provides for senior secured borrowings consisting of (a) a one-year, $25 million term loan and (b) a three-year revolving credit facility that may be used for revolving credit loans and letters of credit from time to time up to a maximum principal amount of $125 million, including the $25 million term loan, subject to limitations described below in this paragraph. The maximum amount of letters of credit that may be outstanding at any one time is $20 million and the amount available under the revolving credit facility is limited by the borrowing base. The initial borrowing base at closing was $70 million, including the $25 million term loan. At December 31, 2009, the borrowing base was $63.8 million, including the $18.8 million remaining balance on the term loan. The borrowing base is subject to semi-annual redeterminations based on the proved reserves of the oil and gas properties that serve as collateral for the Credit Facility. We were subject to our first borrowing base redetermination beginning in December 2009, and our borrowing base has been reaffirmed at $45 million plus the remaining balance on the term loan. Monthly scheduled repayments of the $25 million term loan, each in the amount of $2.1 million, reduce the borrowing base by the principal amount of each such repayment. Our obligations under the Credit Facility and under derivative contracts with the Lenders are guaranteed by our material subsidiaries and secured by our real property assets and the oil and gas properties to which 90% of the present value of our proved reserves is attributable (the Collateral).

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Credit Facility permits both base rate based borrowings and LIBOR borrowings, in each case plus a floating spread. The spread will float up or down based on our utilization under the credit facilities (the Utilization Level). The spread can range from 3.00% to 3.50% for base rate borrowings and 4.00% to 4.50% for LIBOR borrowings. The credit agreement includes a LIBOR floor of 2.00%. We incur a commitment fee on the unused portion of the borrowing base at a rate ranging from 0.75% to 1.00% based upon the Utilization Level.

The term loan must be repaid in twelve installments of approximately $2.1 million each month beginning October 21, 2009, with any remaining principal balance due on September 21, 2010. The revolving credit facility matures on September 21, 2012. With respect to base rate borrowings, accrued interest must be paid on the last day of each fiscal quarter and, with respect to LIBOR borrowings, accrued interest must be paid on (a) the last day of any applicable interest period and (b) if an interest period is six months in length, on the date that is approximately three months after such interest period begins.

The Credit Facility contains customary negative covenants and customary events of default. As described in the Credit Facility, we must maintain, for each period for which a covenant certification is required, (a) a current ratio (as defined in the credit facility) of 1.0 to 1.0, (b) an interest coverage ratio of not less than 2.50 to 1.0, (c) a leverage ratio less than or equal to 1.50 to 1.0, and (d) a coverage ratio, as defined in the credit agreement, with respect to plugging and abandonment obligations. We are also required to maintain a commodities hedging program that is in compliance with the requirements set forth in the Credit Facility. The determination of our borrowing base under the Credit Facility is based on our proved reserves using the Lenders pricing assumptions, and includes the impact of our commodity derivative instruments. The Credit Facility also places restrictions on the maximum estimated future production volumes that can be subject to commodity derivative instruments. In order to meet our objectives in establishing the Credit Facility borrowing base and to conform to the Credit Facility terms, we entered into certain commodity derivative instruments upon our emergence from Chapter 11 reorganization in connection with executing the Credit Facility. See Note 12, Derivative Transactions, for more information regarding outstanding commodity derivative instruments.

PIK Notes

On September 21, 2009, we issued the PIK Notes due 2014 in an aggregate principal amount of $61.1 million pursuant to an indenture dated September 21, 2009 (the Indenture). The PIK Notes were issued with original issue discount, and the note proceeds after this discount were $55.0 million. The PIK Notes allow, or require, as specified in the Indenture, for payment of interest in-kind in the form of newly issued notes having the same terms as the PIK Notes. Interest on the PIK Notes and newly issued PIK Notes issued for payment of periodic interest is payable in additional PIK Notes or in cash subject to the limitations described below and in the Indenture.

Until the first interest payment date that occurs 91 days after the repayment in full of all amounts outstanding under the Credit Facility and the termination of the Lenders commitments under the Credit Facility (such date being, the Credit Facility Termination Date), interest on the PIK Notes will be payable in-kind, semi-annually in arrears on January 1 and July 1 of each year, beginning on January 1, 2010. At December 31, 2009, our total indebtedness related to the PIK Notes includes $3.4 million of accrued interest in-kind for which new notes were issued on January 1, 2010. After the Credit Facility Termination Date, interest on the original PIK Notes and any additional PIK Notes issued for in-kind interest payments, will be payable quarterly in cash in arrears on January 1, April 1, July 1 and October 1 of each year. All of the PIK Notes mature on September 21, 2014 along with all accrued but unpaid interest and the outstanding PIK Note principal balances. We may redeem all or part of the PIK Notes upon not less than 10 days and no more than 60 days notice to each holder of the PIK Notes to be redeemed at a redemption price equal to 100% of the principal amount of the PIK Notes to be redeemed plus accrued and unpaid interest to the date of redemption.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The PIK Notes are (a) subordinated in right of payment to the Credit Facility, (b) guaranteed by our material subsidiaries and (c) (i) prior to the Credit Facility Termination Date, secured by the Collateral or (ii) after the Credit Facility Termination Date, secured by the Collateral plus certain additional real property collateral as may be required under the Indenture. The security interests granted for the benefit of the holders of the PIK Notes are subordinated to those granted in favor of the Lenders.

The Indenture imposes customary negative covenants, which are based on such covenants contained in the Credit Facility, and contains customary events of default, except that there are no financial performance covenants contained in the Indenture.

Predecessor Indebtedness

In April 2007, the Predecessor Company refinanced an existing bank credit facility with a credit agreement, which had availability and a borrowing base of $200 million and was secured by substantially all of our assets (the Pre-Reorganization Credit Agreement). The borrowing base under the Pre-Reorganization Credit Agreement was subject to redetermination based on the proved reserves of the oil and natural gas properties that served as collateral as set out in the reserve report delivered to the banks in April and October each year. In November 2008, the Pre-Reorganization Credit Agreement was redetermined with a borrowing base of $150 million. At December 31, 2008, we had $43 million outstanding under the Pre-Reorganization Credit Agreement. In March 2009, the Pre-Reorganization Credit Agreement was redetermined with a new borrowing base of $45 million. The Predecessor Company had $83 million outstanding under the Pre-Reorganization Credit Agreement, resulting in a deficiency of $38 million and a demand for repayment of the borrowing base deficiency.

While we were not in default under our Pre-Reorganization Credit Agreement as of December 31, 2008, we subsequently failed to timely satisfy a number of Pre-Reorganization Credit Agreement covenants, including those requiring the delivery of our December 31, 2008 debt compliance certificate in April 2009 and providing our December 31, 2008 financial results at that time. On September 21, 2009, outstanding borrowings under the Pre-Reorganization Credit Agreement of $83 million were repaid using proceeds from the Credit Facility and the PIK Notes.

Prior to the redetermination of our borrowing base under the Pre-Reorganization Credit Agreement in March 2009 and the commencement of our filing for reorganization under Chapter 11, the Pre-Reorganization Credit Agreement permitted both prime rate borrowings and LIBOR borrowings plus a floating spread. The spread floated up or down based on utilization of the Pre-Reorganization Credit Agreement. Under the terms of the Pre-Reorganization Credit Agreement, the interest rate spread ranged from 1.00% to 2.5% above LIBOR and 0% to 0.50% above prime. In addition we paid an annual fee on the unused portion of the facility, ranging between 0.25% to 0.50% based on utilization. The Pre-Reorganization Credit Agreement contained customary events of default and various financial covenants, which required us to maintain: (1) a minimum current ratio, as defined by the Pre-Reorganization Credit Agreement, of 1.0x, (2) a minimum Consolidated EBITDAX to interest ratio, as defined by the Pre-Reorganization Credit Agreement, of 2.5x, and (3) a ratio of long-term debt to Consolidated EBITDAX below 3.0. Our failure to cure the borrowing base deficiency by May 1, 2009 constituted an event of default under our Pre-Reorganization Credit Agreement. Subsequent to such date, we were paying interest at the foregoing rates plus 2.00% per annum (the default rate).

The current ratio, as defined by the Pre-Reorganization Credit Agreement, included (among other terms) in current assets our unused availability on the Pre-Reorganization Credit Agreement for purposes of satisfying the minimum current ratio covenant. As a result, for purposes of complying with the minimum current ratio covenant at each quarterly compliance reporting date, our working capital deficit, as adjusted by the terms of the Pre-Reorganization Credit Agreement, reduced the amount available for borrowings under the Pre-Reorganization Credit Agreement.

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In April 2007, the Predecessor Company also completed an offering of the Senior Unsecured Notes, consisting of $300 million aggregate principal amount of the Fixed Rate Notes, with interest payable semi-annually on April 15 and October 15 beginning on October 15, 2007, and $150 million aggregate principal amount of the Floating Rate Notes. Interest on the Floating Rate Notes was payable quarterly on January 15, April 15, July 15 and October 15, beginning in July of 2007. In May 2007, the Predecessor Company completed a cash tender offer for the $150 million 8.75% Senior Notes due 2010. Approximately $145.5 million of the 8.75% Senior Notes due 2010 were repurchased.

As described in Note 3, Reorganization and Fresh-Start Accounting, the Predecessor Company Notes and the related indentures were cancelled in connection with the reorganization, resulting in a loss on debt discharge of $2.7 million during the period from January 1, 2009 through September 30, 2009. In addition, the outstanding borrowings under the Pre-Reorganization Credit Agreement and related accrued interest were repaid.

Principal maturities of the Successor Company s indebtedness outstanding as of December 31, 2009, based on the contractual terms, are as follows (in thousands):

2010	$ 18,750
2011	
2012	
2013	
2014	64,507

(11) Significant Customers

We had oil and natural gas sales to three customers accounting for 36%, 19% and 14%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the period from October 1, 2009 through December 31, 2009. We had oil and natural gas sales to three customers accounting for 30%, 27% and 21%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the period from January 1, 2009 through September 30, 2009. We had oil and natural gas sales to three customers accounting for 38%, 24% and 23%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2008.

(12) Derivative Transactions

We enter into derivative transactions to reduce exposure to fluctuations in the price of oil and natural gas for a portion of our production. Our put contracts limit our exposure to declines in the sales price of oil for a limited amount of our production. Our fixed-price swaps fix the sales price for a limited amount of our production and, for the contracted volumes, eliminate our ability to benefit from increases in the sales price of the production. Derivative contracts are carried at their fair value on the consolidated balance sheets as Fair value of commodity derivative instruments and all unrealized and realized gains and losses are recorded in Gain (loss) on derivative instruments in Other income (expense) in the consolidated statements of operations.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2009, the following derivative instruments were outstanding:

Oil Contracts

	Fixed-Price Swaps			Puts		
Remaining Contract Term	Daily Average Volume (Bbls)	Volumes (Bbls)	Average Swap Price ($/Bbl)	Daily Average Volume (Bbls)	Volume (Bbls)	Floor Price ($/Bbl)
January 2010 July 2010	3,053	647,250	$ 67.34	502	106,500	$ 60.00
August 2010 November 2010	625	76,200	$ 69.65	1,673	204,150	$ 60.00
December 2010	1,200	37,200	$ 70.37	1,302	40,350	$ 60.00
January 2011 July 2011	2,261	479,250	$ 71.13	502	106,500	$ 60.00
August 2011 November 2011	502	61,200	$ 72.18	1,301	158,700	$ 60.00
December 2011	948	29,400	$ 72.64	1,302	40,350	$ 60.00

Natural Gas Contracts

	Puts		
Remaining Contract Term	Daily Average Volume (Mmbtu)	Volume (Mmbtu)	Floor Price ($/Mmbtu)
January 2010	24,000	744,000	$ 4.00
February 2010	25,000	700,000	$ 4.00
March 2010	25,000	775,000	$ 4.00
April 2010	25,000	750,000	$ 4.00
May 2010	23,000	713,000	$ 4.00
June 2010	22,000	660,000	$ 4.00

During the period from January 1, 2009 through September 30, 2009, we had agreed to termination of our derivative contracts as requested by our lenders or as required by the terms of our agreements with them. The following table presents information about the components of gain (loss) on derivative instruments:

	Successor	Predecessor Company	
(In thousands)	Company Period from October 1, 2009 through December 31, 2009	Period from January 1, 2009 through September 30, 2009	Year Ended December 31, 2008
Derivative contracts:			
Unrealized gain (loss) due to change in fair market value	$ (21,739)	$	$ 19,057
Realized gain (loss) on settlement	(966)	2,728	(17,004)
Total gain (loss) on derivative instruments	$ (22,705)	$ 2,728	$ 2,053

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(13) Fair Value Measurements

ASC Topic 820, Fair Value Measurements and Disclosures, establishes a fair value hierarchy with three levels based on the reliability of the inputs used to determine fair value. These levels include: Level 1, defined as inputs such as unadjusted quoted prices in active markets for identical assets and liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

As of December 31, 2009 and 2008, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, primarily our commodity derivative instruments. At December 31, 2009 and 2008, the fair values of derivative instruments were estimated using similar, observable NYMEX published settlements and are included within the Level 2 fair value hierarchy. The following tables present our assets and liabilities that are measured at fair value on a recurring basis:

	Successor Company As of December 31, 2009				
			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Financial Assets (Liabilities) (in thousands):					
Derivative instruments	$ 2,141	$ 2,141	$	$ 2,141	$
Derivative instruments	$ (17,775)	$ (17,775)	$	$ (17,775)	$

	Predecessor Company As of December 31, 2008				
			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Financial Assets (Liabilities) (in thousands):					
Derivative instruments	$ 5,415	$ 5,415	$	$ 5,415	$
Derivative instruments	$ (83)	$ (83)	$	$ (83)	$

The fair value of cash and cash equivalents, accounts receivable, accounts payable (including income taxes payable and accrued expenses) and our variable rate debt approximated the carrying amount at December 31, 2009 and 2008. As of December 31, 2009, we estimated that the fair value of our PIK Notes approximated the carrying amount of $58.6 million. We based this estimate on the assumption that the PIK Notes were negotiated during the reorganization proceedings and their terms reflected fair value at the time of our emergence from Chapter 11 reorganization and continue to reflect fair value since our financial condition and market conditions have not changed significantly since that date. The PIK Notes are not traded and therefore quoted prices were not available. As of December 31, 2008, the fair value and carrying value of the Predecessor Company Notes were $454.5 million and $148.3 million, respectively. We estimated the fair value of these debt instruments based on prices reflected by trades which occurred near December 31, 2008 as obtained through financial information services.

In January 2009, we adopted ASC 820 for our non-financial assets and non-financial liabilities that are remeasured at fair value on a non-recurring basis. As described in Note 2, we evaluate our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicate that the carrying values may not be recoverable. Our assessment of possible impairment of proved oil and natural gas properties is

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based on our best estimate of future prices, costs and expected net future cash flows by property. An impairment loss is indicated if undiscounted net future cash flows are less than the carrying value of a property. The impairment expense is measured as the shortfall between the net book value of the property and its estimated fair value measured based on the discounted net future cash flows from the property.

As addressed in Note 3, Reorganization and Fresh-Start Accounting, we have applied fair value concepts in allocating the reorganization value of the Company to our assets and liabilities as a result of the reorganization and application of ASC 852. The inputs to the fair values of our more significant assets and liabilities are addressed in Note 3.

(14) Income Taxes

Components of income tax benefit for the periods from October 1, 2009 through December 31, 2009 and January 1, 2009 through September 30, 2009 and the year ended December 31, 2008 are as follows:

	Successor Company	Predecessor Company	
	October 1, 2009 through December 31, 2009	January 1, 2009 through September 30, 2009	2008
	(In thousands)		
Current:			
Federal	$	$	$
State			
	$	$	$
Deferred:			
Federal	$ 11,076	$	$ 16,542
State	324		473
	$ 11,400	$	$ 17,015
Total:			
Federal	$ 11,076	$	$ 16,542
State	324		473
	$ 11,400	$	$ 17,015

The reasons for the differences between the effective tax rates and the expected corporate federal income tax rate are as follows:

	Percentage of Pretax Earnings		
	Successor Company	Predecessor Company	
	October 1, 2009 through	January 1, 2009 through September 30,	2008

	December 31, 2009	2009	
Expected tax rate	35.0%	35.0%	35.0%
State taxes	1.0	1.0	1.0
Valuation allowance		(41.0)	(10.8)
Other	(0.8)	5.0	(0.6)
	35.2%	0%	24.6%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The tax effects of temporary differences that give rise to significant portions of the current tax asset and net deferred tax liability at December 31, 2009 and 2008 are presented below:

	Successor Company 2009	Predecessor Company 2008
	(In thousands)	
Current deferred tax assets (liabilities):		
Fair value of commodity derivative instruments	$ 3,363	$ (1,636)
Other	2,405	56
Net current deferred tax asset (liability)	$ 5,768	$ (1,580)
Non-current deferred tax assets:		
Restricted stock awards and options	$	$ 6,268
Federal and state net operating loss carryforwards	47,952	65,953
Fair market value of commodity derivative instruments	2,265	24
Other	4,048	741
Valuation allowance		(7,465)
Non-current deferred tax asset	54,265	65,521
Non-current deferred tax liabilities:		
Property, plant and equipment, principally due to differences in depreciation	(71,219)	(63,941)
Net non-current deferred tax asset (liability)	$ (16,954)	$ 1,580

Under the applicable income tax rules and regulations, we would not be required to recognize taxable income resulting from the discharge of indebtedness (described in Note 3, Reorganization and Fresh-Start Accounting) that may result under the application of the tax rules and regulations to the discharge of debt in a Chapter 11 proceeding. Generally, the income, represented for tax purposes as the excess of the principal and accrued interest on the debt discharged over the fair value of the stock of the reorganized company received in exchange for the discharged obligations, as defined by Internal Revenue Code (the IRC) Section 108 (IRC 108), would reduce our tax attribute carryovers (net operating loss carryforwards (NOLs), other deduction carryforwards, and credit carryforwards) or reduce the tax basis in certain assets (collectively, Tax Attribute Reduction), immediately following the end of 2009, unless we elect to defer the income at the time we file our federal tax return. For purposes of applying the tax rules and regulations, we estimate that the principal of, and accrued interest on, the discharged debt exceeds the value of the common stock received by the former holders and, as a result, we expect to recognize Tax Attribute Reduction. In the accompanying consolidated financial statements, we have recognized the estimated Tax Attribute Reduction as a reduction of our NOLs as of December 31, 2009, resulting in a reduction of our non-current deferred tax asset related to NOLs. Our estimated NOLs at December 31, 2009, after application of the estimated Tax Attribute Reduction, are approximately $133 million.

Prior to December 31, 2009, our net deferred tax position had changed from a net deferred tax liability position to a net deferred tax asset position, before consideration of the valuation allowance. We were not able to conclude that it was more likely than not that our net deferred tax assets would be realized through future earnings and reversal of taxable temporary differences, primarily due to the existence of cumulative book losses for the three year period ended December 31, 2008. As a result, we had previously provided a valuation allowance of $7.5 million as of December 31, 2008, which reduced our net deferred tax asset to zero. The Tax Attribute Reduction changed our net deferred tax position, before consideration of the valuation allowance, from

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a net deferred tax asset to a net deferred tax liability, which eliminated the need for the valuation allowance; thus, we reversed all of the previously established valuation allowance as of December 31, 2009.

The Company s Chapter 11 reorganization caused a change in ownership of the Company within the meaning of IRC Section 382 and related regulations (IRC 382). As a result, the annual usage of our tax attribute carryforwards generally would be limited under IRC 382 (the Section 382 Limitation), to the federal long-term tax exempt rate times the value of the Company s stock immediately after the change in ownership. Based on our estimates regarding the value of the Company s stock and the application of relevant regulatory provisions, we believe the Section 382 Limitation will be approximately $20 million.

Our NOLs as of December 31, 2009 are available to reduce future federal taxable income subject to the limitations and estimates described above and the application of the tax rules and regulations. The NOLs begin expiring in the years 2018 through 2029. We believe that we have net unrealized built-in gains that will be recognized under IRC 382 that would sufficiently add to the Section 382 Limitation, making it more likely than not that a valuation allowance is not needed against the NOLs and other tax attributes.

As of January 1, 2010, our 2006-2008 income tax years remain subject to examination by the Internal Revenue Service, as well as the Louisiana Department of Revenue. In addition, Texas Franchise Tax calendar years 2006-2008 remain subject to examination.

(15) Employee Benefit Plans

Stock-Based Compensation Plans

The Board of Directors of the Successor Company adopted the Energy Partners, Ltd. 2009 Long Term Incentive Plan (the 2009 LTIP). The purpose of the 2009 LTIP is to provide a means to enhance our profitable growth by attracting and retaining directors, officers and other key employees through affording such individuals a means to acquire and maintain stock ownership or awards the value of which is tied to the performance of our common stock. All directors, officers and other key employees providing services to the Company are potentially eligible to participate in the 2009 LTIP. The 2009 LTIP provides for grants of (i) incentive stock options qualified as such under income tax rules and regulations, (ii) stock options that do not qualify as incentive stock options, (iii) restricted stock awards, (iv) restricted stock units, (v) stock appreciation rights, (vi) bonus stock and awards in lieu of Company obligations, (vii) dividend equivalents in connection with other awards, (viii) deferred shares, (ix) performance units or shares, or (x) any combination of such awards (collectively referred to as Awards). The Plan is administered by a committee of our Board of Directors.

The maximum aggregate number of shares of our common stock that may be issued pursuant to any and all Awards under the 2009 LTIP is limited to 1,237,000 shares, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or the expiration of Awards, as provided under the 2009 LTIP. As of December 31, 2009, 1,121,258 shares remain available for future grants.

Without stockholder or participant approval, the Board of Directors may amend, alter, suspend, discontinue or terminate the 2009 LTIP or the Committee s authority to grant Awards under the 2009 LTIP, except that any amendment or alteration of the 2009 LTIP, including any increase in any share limitation, shall be subject to the approval of the stockholders not later than the next annual meeting if stockholder approval is required by any state or federal law or regulation or the rules of any stock exchange or automated quotation system on which the common stock may then be listed or quoted.

Pursuant to an employment agreement and the 2009 LTIP, on September 30, 2009, our new chief executive officer was granted an option to purchase 68,116 shares of Successor Company common stock, which was

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memorialized in an option award agreement dated as of October 1, 2009 (the Option Agreement). The terms of the Option Agreement provide for an exercise price equal to $10.00 per share. The closing price of our common stock on the NYSE on September 30, 2009 was $7.46 per share. The option vests ratably on a monthly basis over a 36-month period from the date of grant; provided, however, that the vesting for the first six months of the vesting period (the Initial Period) is deferred until the end of the Initial Period and any remaining unvested portion vests ratably on a monthly basis over the remainder of the 36-month vesting period, subject to the executive remaining continuously employed. Vested stock options under the Option Agreement expire 30 months following the applicable vesting date of such stock options. Upon a change in control as defined in the 2009 LTIP, all remaining unvested stock options under the Option Agreement automatically vest and remain exercisable for a period of not less than 30 months following the change in control.

In connection with the appointment of the five members of the Board of Directors of the Successor Company and pursuant to the 2009 LTIP, the five directors were awarded, in the aggregate, a total of 43,460 shares of restricted stock, of which one-half vested immediately (in the case of four of the directors) and one-half will vest on the day immediately preceding the date of the 2010 Annual Meeting of Stockholders. In the case of the fifth director, he had deferred the receipt of his 2009 stock award until he ceases to serve on our Board of Directors under an election made while he was also a director of the Predecessor Company.

Prior to the reorganization, the Predecessor Company had two stock-based compensation plans, which are more fully described below. Pursuant to the Plan, all stock option or other equity awards outstanding under these plans became fully vested and were deemed exercised or were cancelled. The number of shares of Predecessor Company common stock that were issued as a result of accelerated vesting of prior restricted stock grants totaled 147,372 shares, which shares were converted into 9,103 shares of Successor Company common stock upon emergence from Chapter 11 reorganization. All Predecessor Company stock and incentive plans for employees were deemed cancelled under the Plan.

The 2006 Long Term Stock Incentive Plan provided for the grant of stock options for which the exercise price, set at the time of the grant, was not less than the fair market value per share at the date of grant. The outstanding options had a term of 10 years and generally vested over three years with grants to a limited group of people that cliff vested at the end of five years.

The Amended and Restated 2000 Stock Incentive Plan for Non-Employee Directors (the Director Plan) was adopted by the Board of Directors in March 2005 and approved by our stockholders in May 2005. The Director Plan permitted the use of restricted share units in addition to stock options to provide flexibility to adjust grants to maintain a competitive equity component for non-employee directors. The option exercise price for an option granted under the Director Plan was the fair market value of the shares covered by the option at the time the option was granted. Options became fully exercisable on the first anniversary of the date of the grant. Prior to the one-year anniversary, the options were exercisable as to a number of shares covered by the option determined by pro-rating the number of shares covered by the option based on the number of days elapsed since the date of the grant. Any portion of an option that had not become exercisable prior to the cessation of the optionee s service as a director for any reason would not thereafter become exercisable. Each option was to expire on the earlier of (1) 10 years from the date of the granting thereof, or (2) 36 months after the date the optionee ceased to be a director of the Company for any reason. Each restricted share unit represented the right to receive one share of Common Stock upon the earlier to occur of: (1) the cessation of the eligible director s service as a director of the Company for any reason, or (2) the occurrence of a change of control of the Company. An eligible director became 100% vested in a grant of restricted share units on the first anniversary of the date of grant.

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A summary of option share activity for the year ended December 31, 2009 is as follows:

	Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Terms (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding on December 31, 2008	2,339,919	$ 16.12		
Granted	68,116	10.00		
Forfeited/Cancelled	(2,339,919)	16.12		
Outstanding on December 31, 2009	68,116	$ 10.00	3.8	$
Exercisable on December 31, 2009		$		$

The fair value of each share option award was estimated on the date of grant using the Black-Scholes option valuation model with the weighted average assumptions in the table below for the period from January 1, 2009 through September 30, 2009 and for the year ended December 31, 2008. No share option awards were granted during the period from October 1, 2009 through December 31, 2009.

	January 1, 2009 through September 30, 2009	Year Ended December 31, 2008
Black-Scholes option pricing model assumptions:		
Risk free interest rate	1.9%	4.5%
Expected life (years)	4.0	4.95
Expected volatility	52%	38%
Dividend yield		

Expected volatility is generally based on the historical volatility of our stock over the period of time equivalent to the expected term of the options granted. As a result of our reorganization for purposes of determining expected volatility in 2009, we have included consideration of the historical volatility of the share prices of our peers over the relevant time period in addition to our historical volatility before, during and after our reorganization. We disregarded our share price for the periods during which our stock price was impacted by factors leading up to the Chapter 11 filing and during the period of the Chapter 11 reorganization proceedings because we do not expect these events to reoccur during the expected term of the options. The expected term of options granted is generally derived from historical exercise patterns over a period of time, with consideration of expected term of unvested options. However, due to the unique vesting schedule of the option award to our new chief executive officer during 2009, we have based the expected term assumption on the weighted average contractual term of the option shares, taking into account the vesting schedule and other factors, including expected exercise and post-vesting employment termination behavior. The risk-free interest rate is based on the interest rate on constant maturity bonds published by the Federal Reserve with a maturity commensurate with the expected term of the options granted.

The weighted-average grant-date fair value of option shares granted during the period from January 1, 2009 through September 30, 2009 and the year ended December 31, 2008 was $2.48 and $4.53, respectively. No option shares were exercised during the period from January 1, 2009 through September 30, 2009 or from October 1, 2009 through December 31, 2009. The aggregate intrinsic value of option shares (the amount by which the market price of the stock on the date of exercise exceeded the market price of the stock on the date of grant) exercised during the year ended December 31, 2008 was $0.4 million.

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A summary of the activity related to our non-vested share awards for the year ended December 31, 2009 is as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested share awards outstanding at December 31, 2008	433,700	$ 20.22
Granted	43,460	7.67
Vested	(394,158)	19.78
Forfeited/Cancelled	(61,272)	18.55
Non-vested share awards outstanding at December 31, 2009	21,730	$ 7.67

The fair value of non-vested share awards equals the market value of the underlying stock on the date of grant. The weighted-average grant-date fair value of the non-vested share awards granted during the period from October 1, 2009 through December 31, 2009 and the year ended December 31, 2008 was $7.67 per share and $12.50 per share, respectively. No non-vested share awards were granted during the period from January 1, 2009 through September 30, 2009. The total fair value of non-vested share awards that vested during the period from October 1, 2009 through December 31, 2009, the period from January 1, 2009 through September 30, 2009 and the year ended December 31, 2008 was $0.2 million, $0.1 million and $2.4 million, respectively.

The following table reports stock-based compensation expense and related tax benefits recognized for the periods from October 1, 2009 through December 31, 2009 and January 1, 2009 through September 30, 2009 and the year ended December 31, 2008:

	Successor Company	Predecessor Company	
	October 1, 2009 through December 31, 2009	January 1, 2009 through September 30, 2009	2008
		(in thousands)	
Compensation Expense (Benefit):			
Option shares	$ 14	$ 1,001	$ 2,127
Non-vested share awards	229	2,688	4,274
Employee bonus share awards	174		
Performance share awards			(293)
Deferred Income Tax Benefit	150	1,328	2,199

As of December 31, 2009, $0.2 million of total unrecognized compensation expense related to outstanding option shares was expected to be recognized over a weighted-average period of 2.7 years. As of December 31, 2009, $0.1 million of total unrecognized compensation expense related to non-vested share awards was expected to be recognized over a weighted-average period of approximately five months.

We also have a 401(k) Plan that covers all employees. We match 100% of each individual participant s contribution not to exceed 6% of the participant s compensation. Our matching contributions were made in common stock of EPL until 2009. During 2009, our 401(k) Plan was amended to require matching contributions to be made in cash. During the periods from October 1, 2009 through December 31, 2009 and January 1, 2009 through September 30, 2009, we made matching contributions in cash to the 401(K) Plan of approximately $0.2 million and $0.5 million, respectively. During 2008, we made matching contributions to the 401(k) Plan of 266,365 shares of common stock valued at approximately $0.9 million.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Employee Retention Plans

In June 2009, we executed retention agreements with all of our non-officer, non-field employees, which called for payments of one-half of the retention amounts upon execution of the agreements and the remaining one-half upon exit from our Chapter 11 reorganization. Our field employees also received payments under this program. We also executed agreements with all of our officers (except for two executive officers who had individual change of control severance agreements with the Company) that called for payments of the entire retention amount upon exit from our Chapter 11 reorganization. During the period from January 1, 2009 through September 30, 2009, we recorded approximately $2.0 million for cash payments under these agreements. In addition, the remaining two executive officers terminated their written change of control severance agreements with the Company in exchange for receiving an unsecured claim for rejection damages in the Chapter 11 reorganization. In connection with these retention agreements, non-field employees and officers were required to waive and release the Company from any and all potential claims with respect to certain incentive and retention plans and agreements as provided for in the retention agreements. During the period from January 1 through September 30, 2009, we reduced previously established accruals totaling approximately $2.0 million for the various incentive and retention plans and agreements that were waived and released.

The Company has two plans under which, in the event of termination of employment in connection with a change of control of our company, our officers and employees are entitled to receive a multiple of their salaries and bonuses (typically up to one or two times such amount) and certain other benefits in a lump sum cash payment. Additionally, all options, restricted stock, restricted share units and other similar awards would become fully vested.

Other

In November 2008, we discontinued a plan that was designed to fund post-employment benefits to a limited group of key non-executive employees through whole life insurance policies, while providing life insurance coverage for the participants during the participation period. The cash surrender value of the cancelled whole life insurance policies distributed to the participants in January 2009 was $0.2 million.

(16) Commitments and Contingencies

As described in Notes 1 and 3, on May 1, 2009, we and certain of our subsidiaries filed for reorganization under Chapter 11.

We have operating leases for office space and equipment, which expire on various dates through 2016. Future minimum commitments as of December 31, 2009 under these operating obligations are as follows (in thousands):

2010	$ 559
2011	622
2012	629
2013	633
2014	616
Thereafter	1,035
	$ 4,094

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Expense relating to operating obligations for the periods from October 1, 2009 through December 31, 2009 and January 1, 2009 through September 30, 2009 and the year ended December 31, 2008 was $0.7 million, $1.9 million and $5.4 million, respectively.

We maintain restricted escrow funds in a trust for future abandonment costs at our East Bay property. The trust was originally funded with $15 million and, with accumulated interest, increased to $16.7 million at December 31, 2008. We may draw from the trust upon completion of qualifying abandonment activities at our East Bay field. At December 31, 2009, we had $13.3 million remaining in restricted escrow funds for decommissioning work in our East Bay field, $7.3 million of which will be available for draw currently upon completion of certain decommissioning activities as that work progresses; the remaining $6.0 million will remain restricted until substantially all required decommissioning in the East Bay field is complete. Through December 31, 2009, we had made draws of $3.4 million. Amounts on deposit in the trust account are reflected in restricted cash on our consolidated balance sheets.

On February 21, 2008, we entered into a plea agreement with the United States Department of Justice under which we pled guilty on that same date to one strict liability, misdemeanor violation of the River and Harbors Act in the United States District Court for the Eastern Division of Louisiana. The plea concludes the investigation announced in June 2007 into possible environmental violations at our East Bay properties in late 2005 and early 2006. Under the plea agreement, in 2008 we paid a fine of $75,000 and made a community service payment of $25,000 to a Louisiana state agency. As a part of the plea agreement, we were subject to inactive probation for one year. The foregoing actions represent the final resolution of this matter with all federal agencies involved with the investigation.

We generate liabilities related to production that is delivered to us in excess of our interest in certain properties, often referred to as production imbalances. Additionally, we may, from time to time, receive cash in excess of amounts that we estimate are due to us for our interest in production, which amounts may be subject to further review, may require more information to resolve or may be in dispute. During 2008, we reduced revenue by $4.4 million reflecting our estimate of amounts that, based on information available to us, may be subject to claim by one purchaser of our production. During the periods from October 1, 2009 through December 31, 2009 and January 1, 2009 through September 30, 2009, we reduced revenue by $0.1 million and $0.5 million, respectively, increasing our estimate to $5.0 million as of December 31, 2009. As of December 31, 2009 and 2008, this amount is included in accrued expenses.

In the ordinary course of business, we are a defendant in various other legal proceedings. We do not expect our exposure in these other proceedings, individually or in the aggregate, to have a material adverse effect on our financial position, results of operations or liquidity.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(17) Interim Financial Information (Unaudited)

The following is a summary of consolidated unaudited interim financial information for the years ended December 31, 2009 and 2008:

	Predecessor Company Three Months Ended			Successor Company Three Months Ended
	March 31 (1)	June 30	September 30	December 31
	(In thousands, except per share data)			
2009				
Revenues	$ 42,700	$ 46,076	$ 46,109	$ 56,750
Costs and expenses	66,804	62,625	57,964	61,273
Business interruption recovery	1,185			
Loss from operations	(22,919)	(16,549)	(11,855)	(4,523)
Net income (loss) (2)	(31,871)	(33,661)	29,418	(21,012)
Earnings (loss) per share:				
Basic	$ (0.99)	$ (1.05)	$ 0.91	$ (0.53)
Diluted	(0.99)	(1.05)	0.91	(0.53)

(1) Costs and expenses and loss from operations exclude reorganization items totaling $0.9 million which were reclassified due to the application of ASC 852 as a result of our filing for reorganization under Chapter 11. See Note 4 for additional information regarding reorganization items.

(2) Included in net income (loss) for the three months ended March 31, June 30, September 30 and December 31 are reorganization items totaling $0.9 million, $11.7 million, $11.6 million and $0.9 million, respectively.

	Predecessor Company Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share data)			
2008				
Revenues	$ 97,496	$ 125,688	$ 94,672	$ 38,396
Costs and expenses	73,863	71,466	57,738	182,964
Business interruption recovery				4,248
Income (loss) from operations	23,633	54,222	36,934	(140,320)
Net income (loss)	2,315	3,996	34,445	(92,968)
Earnings (loss) per share:				
Basic	$ 0.07	$ 0.13	$ 1.07	$ (2.90)
Diluted	0.07	0.12	1.07	(2.90)

(18) New Accounting Pronouncements

Effective for our financial statements as of September 30, 2009, the ASC is the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. The ASC superseded all then-existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the ASC is no longer authoritative. While the ASC does not change GAAP, it introduces a new structure that reorganizes the GAAP pronouncements into accounting topics. All content of the ASC carries the same level of authority.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In January 2010, the FASB issued Accounting Standards Update No. 2010-03 (ASU 2010-03), Oil and Gas Reserve Estimation and Disclosures, which amends the oil and gas reserve estimation and disclosure requirements of ASC Topic 932, Extractive Industries Oil and Gas (ASC 932) in order to align its requirements with the requirements in the SEC s final rule, Modernization of the Oil and Gas Reporting Requirements, which are described in Note 19 below. ASU 2010-03 is first effective for this Annual Report.

(19) Supplementary Oil and Natural Gas Disclosures (Unaudited)

In December 2008, the SEC issued a final rule, Modernization of Oil and Gas Reporting, which amended its oil and gas reserves estimation and disclosure requirements. The new requirements were codified into the ASC as part of ASC 932 in January 2010, and had the effect of, among other things: permitting the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; modifying the prices used to estimate reserves for SEC disclosure purposes to an average price based upon the prior twelve month period rather than the year-end price; allowing the optional disclosure of probable and possible reserves to investors; allowing reserves to be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years (unless the specific circumstances justify a longer time); requiring disclosure regarding the qualifications of the chief technical person who oversees the reserves estimation process; requiring a general discussion of our internal controls used to ensure the objectivity of the reserves estimation process; and requiring that, if a third party is primarily responsible for preparing or auditing the reserve estimates, the company make disclosures relating to the independence and qualifications of the third party, including filing as an exhibit any report received from the third party. The revised rule was effective January 1, 2010 for reporting December 31, 2009 annual oil and natural gas reserve information. We have adopted the provisions of the final rule in connection with the filing of this Annual Report.

Our estimates of proved reserves are based on reserve reports prepared as of December 31, 2009 by independent petroleum engineering firms Netherland, Sewell & Associates, Inc. and Ryder Scott Company, L.P. Users of this information should be aware that the process of estimating quantities of proved and proved-developed natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates 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. Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved-developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the changes in our estimated net proved reserves and proved-developed reserves:

	Crude Oil (Mbbls)	Natural Gas (Mmcf)	Barrels of Oil Equivalent (Mboe)
Estimated Proved Reserves:			
December 31, 2007	28,123	103,118	45,309
Sales of reserves in place	(265)	(1,819)	(568)
Extensions, discoveries and other additions (a)	956	8,482	2,370
Revisions (b)	(5,125)	(2,477)	(5,538)
Production	(2,052)	(16,496)	(4,802)
December 31, 2008	21,637	90,808	36,771
Extensions, discoveries and other additions	70	2,203	437
Revisions	176	(4,765)	(617)
Production	(1,960)	(20,868)	(5,438)
December 31, 2009	19,923	67,378	31,153
Proved-developed reserves:			
December 31, 2008	17,052	79,413	30,288
December 31, 2009	15,026	57,139	24,549

(a) Includes approximately 1.2 Mmboe associated with discoveries in Greater Bay Marchand and approximately 0.4 Mmboe associated with discoveries at our East Bay field.

(b) Comprised of approximately 3.5 Mmboe of negative revisions associated with price decreases in both oil and natural gas and approximately 2.0 Mmboe of negative revisions associated with underperformance of wells.

Capitalized costs for oil and natural gas producing activities consist of the following:

	2009	2008
	(In thousands)	
Proved properties	$ 618,508	$ 1,601,748
Unproved properties	28,606	36,274
Accumulated depreciation, depletion and amortization	(37,419)	(951,316)
Net capitalized costs	$ 609,695	$ 686,706

Costs incurred for oil and natural gas property acquisition, exploration and development activities for the years ended December 31, 2009 and 2008 are as follows:

	Years Ended December 31, 2009	2008

	(In thousands)	
Acquisitions		
-Proved	$	$
-Unproved	85	20,925
Exploration	2,477	56,202
Development (1)	8,815	127,948
Costs incurred	$ 11,377	$ 205,075

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Includes asset retirement obligations incurred associated with finding, acquiring and developing our proved oil and natural gas reserves of \$13.4 million during the year ended December 31, 2008. No asset retirement obligations were incurred associated with finding, acquiring and developing our proved oil and natural gas reserves during the year ended December 31, 2009.

Expenditures incurred for exploratory dry holes are excluded from operating cash flows and included in investing activities in the consolidated statements of cash flows.

Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves

The following information has been developed utilizing procedures prescribed by ASC 932. It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating our performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of our oil and natural gas reserves or the current value of the Company.

We believe that the following factors should be taken into account in reviewing the following information: (1) future costs and sales prices are likely to differ materially from those required to be used in these calculations; (2) due to future market conditions, governmental regulations and other factors, actual rates of production achieved in future years may vary significantly from the rate of production assumed in the calculations; (3) the use of a 10% discount rate, while mandated under ASC 932, is arbitrary and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and (4) future net revenues may be subject to different rates of income taxation.

The Standardized Measure of Discounted Future Net Cash Flows uses future cash inflows estimated using oil and natural gas prices computed by applying the use of physical pricing based on the simple average of the closing price on the first day of each of the twelve months during the fiscal year (as required by ASC 932) and by applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price. These adjustments can vary significantly over time both in amount and as a percentage of the posted price, especially related to our oil prices during periods when the market price for oil varies widely. The price adjustments reflected in our computed reserve prices may not represent the amount of price adjustments we may actually obtain in the future when we sell our production. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs with the assumption of the continuation of existing economic conditions in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying period-end statutory tax rates to aggregate future net cash flows, reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% annual discount rate in computing Standardized Measure of Discounted Future Net Cash Flows is required by ASC 932.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows:

	2009	2008
	(In thousands)	
Future cash inflows	$ 1,416,474	$ 1,517,701
Future production costs	(543,328)	(612,934)
Future development costs	(338,375)	(347,107)
Future income tax expense	(2,964)	(15,176)
Future net cash flows after income taxes	531,807	542,484
10% annual discount for estimated timing of cash flows	(138,005)	(126,313)
Standardized measure of discounted future net cash flows	$ 393,802	$ 416,171

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the years ended December 31, 2009 and 2008 is as follows:

	2009	2008
	(In thousands)	
Beginning of the period	$ 416,171	$ 1,092,935
Sales and transfers of oil and natural gas produced, net of production costs	(133,096)	(277,493)
Net changes in prices and production costs	82,280	(749,426)
Extensions, discoveries and improved recoveries, net of future production costs	9,045	28,437
Revision of quantity estimates	(13,246)	(117,355)
Previously estimated development costs incurred during the period	18,425	27,932
Purchase and sales of reserves in place, net		(21,514)
Changes in estimated future development costs	(6,622)	(46,956)
Changes in production rates (timing) and other	(28,561)	(35,692)
Accretion of discount	42,525	147,029
Net change in income taxes	6,881	368,274
Net decrease	(22,369)	(676,764)
End of period	$ 393,802	$ 416,171

At December 31, 2009 and 2008, the computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on the following computed prices:

	2009	2008
per Mcf for natural gas	$ 3.96	$ 6.05
per barrel for oil	$ 57.70	$ 44.77

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Item 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure***
None.

Item 9A. ***Controls and Procedures***
(a) Evaluation of Disclosure Controls and Procedures

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 our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. This information is also accumulated and communicated to management, including our principal executive officer and our principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, under the supervision and with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the most recent fiscal quarter reported on herein. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2009.

Because of their inherent limitations, disclosure controls and procedures may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that such controls and procedures may become inadequate because of changes in conditions, or that the degree of compliance with the controls or procedures may deteriorate. Accordingly, even effective disclosure controls and procedures can provide only reasonable assurance of achieving their control objectives.

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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with GAAP. In connection with our annual evaluation of internal control over financial reporting, our management, under the supervision and with the participation of our principal executive officer and principal financial officer, assessed the effectiveness as of December 31, 2009, of our internal control over financial reporting based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management s evaluation included an assessment of the design of our internal control over financial reporting and testing of the operating effectiveness of our internal control over financial reporting. Based on that evaluation, our principal executive officer and principal financial officer concluded that our internal controls over financial reporting were effective as of December 31, 2009.

Because of their inherent limitations, internal controls 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. Accordingly, even effective internal controls over financial reporting can provide only reasonable assurance of achieving their control objectives.

KPMG LLP, an independent registered public accounting firm, has issued a report concerning the effectiveness of our internal control over financial reporting as of December 31, 2009. See Report of Independent Registered Public Accounting Firm in Part II, Item 8 of this Annual Report.

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(c) Changes in Internal Control Over Financial Reporting

There were no changes in our system of internal control over financial reporting during the three months ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except as described below.

Since the date of our last Annual Report, we completed the implementation of our previously disclosed remediation action plan, which involved: (1) hiring adequate accounting resources with appropriate accounting expertise; and (2) enhancing existing financial reporting policies and procedures.

During the fourth quarter of 2009, we implemented the following actions which we believe remediate the weaknesses we previously identified: (1) we retained additional resources within the accounting department with sufficient expertise to assist in the preparation of our financial statements and disclosures in accordance with GAAP; and (2) we enhanced and strengthened our written accounting and reporting policies and trained our accounting department employees with respect to the new policies.

Item 9B. ***Other Information***

None.

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PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Except as set forth below, for information required by Item 10 regarding our directors and executive officers, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 20, 2010, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Code of Ethics

We have adopted a Corporate Code of Business Conduct and Ethics that applies to all directors and employees, including our chief executive officer, chief financial officer and controller. A copy of the code is available on our website at www.eplweb.com. A copy of the code is also available, at no cost, by writing to our Corporate Secretary at 201 St. Charles Avenue, Suite 3400, New Orleans, Louisiana, 70170. We will post on our website any waiver of the code granted to any of our directors or executive officers promptly following the date of the amendment or waiver. No such waiver has ever been sought or granted.

Item 11. ***Executive Compensation***

For information required by Item 11, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 20, 2010, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Except as set forth below, for information required by Item 12, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 20, 2010, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Securities Authorized for Issuance under Equity Compensation Plans

The information contained in Part II, Item 5, Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities of this Annual Report is incorporated by reference.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

For information required by Item 13, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 20, 2010, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Item 14. ***Principal Accountant Fees and Services***

For information required by Item 14, see the definitive Proxy Statement of Energy Partners, Ltd. for the Annual Meeting of Stockholders to be held on May 20, 2010, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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PART IV

Item 15. ***Exhibits and Financial Statement Schedules***
(a) *Documents to be filed as part of this Annual Report*

1. Financial Statements

The following items are included in Part II, Item 8 this Annual Report:

2. Financial Statement Schedules

All schedules have been omitted because the information is not required or not in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements and notes thereto.

3. Exhibits

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EXHIBITS

The exhibits marked with the cross symbol ( ) are management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
2.0	Second Amended Joint Plan of Reorganization of Energy Partners, Ltd. and certain of its Subsidiaries Under Chapter 11 of the Bankruptcy Code, as Modified as of July 31, 2009	8-K	001-16179	99.1	08/04/2009	
3.1	Amended and Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 21, 2009	8-K/A	001-16179	3.1	09/21/2009	
3.2	Second Amended and Restated Bylaws of Energy Partners, Ltd.	8-K/A	001-16179	3.2	09/21/2009	
4.1	Indenture by and among Energy Partners, Ltd., as Issuer, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A. as Trustee dated September 21, 2009	8-K	001-16179	10.2	09/25/2009	
10.1	Note Purchase Agreement by and among Energy Partners, Ltd., the Guarantors named therein and the purchasers named therein dated September 21, 2009	8-K	001-16179	10.3	09/25/2009	
10.2	Credit Agreement by and among Energy Partners, Ltd., as Borrower, General Electric Capital Corporation, as Administrative Agent, and certain financial institutions, as Lenders dated September 21, 2009	8-K	001-16179	10.1	09/25/2009	
10.3	Exchange Agreement between Energy Partners, Ltd. and Mellon Investor Services LLC (operating with the service name BNY Mellon Shareowner Services), as Agent dated September 15, 2009	8-K	001-16179	10.4	09/25/2009	
10.4	Change of Control Severance Plan effective as of March 24, 2005	8-K	001-16179	10.2	03/30/2005	
10.5	First Amendment to Change of Control Severance Plan effective as of September 13, 2006	8-K	001-16179	10.3	09/14/2006	
10.6	Second Amendment to Change of Control Severance Plan effective as of April 16, 2008	8-K	001-16179	10.3	05/08/2008	
10.7	Third Amendment to Change of Control Severance Plan dated November 13, 2008	8-K	001-16179	10.2	11/14/2008	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
10.8	Fourth Amendment to Change of Control Severance Plan					X
10.9	Term sheet with the United States Department of the Interior, Minerals Management Service dated April 30, 2009	10-K	001-16179	10.6	08/05/2009	
10.10	Engagement Letter dated March 15, 2008 by and between Energy Partners, Ltd. and Alan Bell (This letter agreement was inadvertently dated March 15, 2008, but the actual effective date is March 15, 2009.)					X
10.11	Senior Management Settlement Agreement dated as of June 30, 2009 by and between Energy Partners, Ltd. and Thomas DeBrock	10-K	001-16179	10.42	08/05/2009	
10.12	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and Stephen D. Longon	10-K	001-16179	10.50	08/05/2009	
10.13	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and John H. Peper	10-K	001-16179	10.51	08/05/2009	
10.14	Energy Partners, Ltd. 2009 Long Term Incentive Plan	S-8	333-162185	4.5	09/29/2009	
10.15	Form of 2009 Long Term Incentive Plan Option Award Agreement	8-K	001-16179	10.5	09/25/2009	
10.16	Form of 2009 Long Term Incentive Plan Restricted Stock Agreement	8-K	001-16179	10.6	09/25/2009	
10.17	Form of Indemnification Agreement for Directors	8-K	001-16179	10.1	11/24/2009	
10.18	Form of Indemnification Agreement for Officers	8-K	001-16179	10.2	11/24/2009	
10.19	Energy Partners, Ltd. Board Compensation Program	8-K	001-16179	10.1	11/12/2009	
10.20	Second Amended and Restated Stock and Deferral Plan for Non-Employee Directors, dated as of November 6, 2009	8-K	001-16179	10.2	11/12/2009	
10.21	Form of Director Deferred Share Agreement	8-K	001-16179	10.3	11/12/2009	
21.1	Subsidiaries of Energy Partners, Ltd.					X
23.1	Consent of KPMG LLP.					X
23.2	Consent of Netherland, Sewell & Associates, Inc.					X
23.3	Consent of Ryder Scott Company, L.P.					X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
31.1	Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes Oxley Act of 2002.					X
31.2	Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes Oxley Act of 2002.					X
32.1	Section 1350 Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes Oxley Act of 2002.					X
32.2	Section 1350 Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes Oxley Act of 2002.					X
99.1	Report of Independent Petroleum Engineers (Netherland Sewell & Associates, Inc.) dated as of February 24, 2010					X
99.2	Report of Independent Petroleum Engineers (Ryder Scott Company, L.P.) dated as of February 24, 2010					X

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GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report in reference to oil and other liquid hydrocarbons.

Boe Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Bcf One billion cubic feet.

Bcfe One billion cubic feet equivalent, with one barrel of oil being equivalent to six thousand cubic feet of natural gas.

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

LOE Lease operating expenditures.

Mbbls One thousand barrels of oil or other liquid hydrocarbons.

Mboe One thousand barrels of oil equivalent.

Mcf One thousand cubic feet of natural gas.

Mmbbls One million barrels of oil or other liquid hydrocarbons.

Mmboe One million barrels of oil equivalent.

Mmbtu One million British Thermal Units.

Mmcf One million cubic feet of natural gas.

plugging and abandonment Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Federal regulations and regulations of many states require plugging of abandoned wells.

proved undeveloped reserves Proved reserves 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.

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

working interest The interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

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SIGNATURES

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

Dated: March 11, 2010

ENERGY PARTNERS, LTD.

By: /s/ GARY C. HANNA
Gary C. Hanna
Chief Executive Officer

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

Signature	Title	Date
/s/ GARY C. HANNA **Gary C. Hanna**	Chief Executive Officer	March 11, 2010
/s/ TIFFANY J. THOM **Tiffany J. Thom**	Senior Vice President, Treasurer and Investor Relations (Principal Financial Officer)	March 11, 2010
/s/ DAVID P. CEDRO **David P. Cedro**	Senior Vice President, Controller (Principal Accounting Officer)	March 11, 2010
/s/ CHARLES O. BUCKNER **Charles O. Buckner**	Director	March 11, 2010
/s/ SCOTT A. GRIFFITHS **Scott A. Griffiths**	Director	March 11, 2010
/s/ MARC MCCARTHY **Marc McCarthy**	Director	March 11, 2010
/s/ STEVEN J. PULLY **Steven J. Pully**	Director	March 11, 2010
/s/ JOHN F. SCHWARZ **John F. Schwarz**	Director	March 11, 2010

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INDEX TO EXHIBITS

The exhibits marked with the cross symbol ( ) are management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
2.0	Second Amended Joint Plan of Reorganization of Energy Partners, Ltd. and certain of its Subsidiaries Under Chapter 11 of the Bankruptcy Code, as Modified as of July 31, 2009	8-K	001-16179	99.1	08/04/2009	
3.1	Amended and Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 21, 2009	8-K/A	001-16179	3.1	09/21/2009	
3.2	Second Amended and Restated Bylaws of Energy Partners, Ltd.	8-K/A	001-16179	3.2	09/21/2009	
4.1	Indenture by and among Energy Partners, Ltd., as Issuer, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A. as Trustee dated September 21, 2009	8-K	001-16179	10.2	09/25/2009	
10.1	Note Purchase Agreement by and among Energy Partners, Ltd., the Guarantors named therein and the purchasers named therein dated September 21, 2009	8-K	001-16179	10.3	09/25/2009	
10.2	Credit Agreement by and among Energy Partners, Ltd., as Borrower, General Electric Capital Corporation, as Administrative Agent, and certain financial institutions, as Lenders dated September 21, 2009	8-K	001-16179	10.1	09/25/2009	
10.3	Exchange Agreement between Energy Partners, Ltd. and Mellon Investor Services LLC (operating with the service name BNY Mellon Shareowner Services), as Agent dated September 15, 2009	8-K	001-16179	10.4	09/25/2009	
10.4	Change of Control Severance Plan effective as of March 24, 2005	8-K	001-16179	10.2	03/30/2005	
10.5	First Amendment to Change of Control Severance Plan effective as of September 13, 2006	8-K	001-16179	10.3	09/14/2006	
10.6	Second Amendment to Change of Control Severance Plan effective as of April 16, 2008	8-K	001-16179	10.3	05/08/2008	
10.7	Third Amendment to Change of Control Severance Plan dated November 13, 2008	8-K	001-16179	10.2	11/14/2008	
10.8	Fourth Amendment to Change of Control Severance Plan					X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
10.9	Term sheet with the United States Department of the Interior, Minerals Management Service dated April 30, 2009	10-K	001-16179	10.6	08/05/2009	
10.10	Engagement Letter dated March 15, 2008 by and between Energy Partners, Ltd. and Alan Bell (This letter agreement was inadvertently dated March 15, 2008, but the actual effective date is March 15, 2009.)					X
10.11	Senior Management Settlement Agreement dated as of June 30, 2009 by and between Energy Partners, Ltd. and Thomas DeBrock	10-K	001-16179	10.42	08/05/2009	
10.12	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and Stephen D. Longon	10-K	001-16179	10.50	08/05/2009	
10.13	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and John H. Peper	10-K	001-16179	10.51	08/05/2009	
10.14	Energy Partners, Ltd. 2009 Long Term Incentive Plan	S-8	333-162185	4.5	09/29/2009	
10.15	Form of 2009 Long Term Incentive Plan Option Award Agreement	8-K	001-16179	10.5	09/25/2009	
10.16	Form of 2009 Long Term Incentive Plan Restricted Stock Agreement	8-K	001-16179	10.6	09/25/2009	
10.17	Form of Indemnification Agreement for Directors	8-K	001-16179	10.1	11/24/2009	
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