

ENERGY PARTNERS LTD
Form 10-K
March 03, 2011
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

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)

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Delaware
(State or other jurisdiction of
incorporation or organization)

72-1409562
(I.R.S. Employer
Identification No.)

201 St. Charles Avenue, Suite 3400

New Orleans, Louisiana
(Address of principal executive offices)

70170
(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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter 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 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.

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 <input type="checkbox"/>	Accelerated filer <input checked="" type="checkbox"/>
Non-accelerated filer <input type="checkbox"/> (Do not check if a smaller reporting company)	Smaller reporting company <input checked="" type="checkbox"/>

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes No

The aggregate market value of the common stock held by non-affiliates of the registrant at June 30, 2010 (the registrant's most recently completed second fiscal quarter) based on the closing stock price as quoted on the New York Stock Exchange on that date was \$353,060,074. As of February 25, 2011, there were 40,175,161 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. expected to be held on May 19, 2011

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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 I 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 based in New Orleans, Louisiana and Houston, Texas. Our current operations are concentrated in the U.S. Gulf of Mexico shelf focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, as it is characterized by established exploitation, development and exploration opportunities in both productive horizons and deeper geologic formations. Our management professionals and technical staff have considerable geological, geophysical and operational experience that is specific to the Gulf of Mexico and Gulf Coast region, and we have acquired and developed geophysical and geological data relating to these areas. We intend to pursue capital-efficient development and exploration activities in our core area, as well as identify acquisition opportunities that leverage our operational strengths. As of December 31, 2010, we had estimated proved reserves of 27.4 million barrels of oil equivalent, or Mmboe, of which 63% were oil and 93% were proved developed. Of these proved developed reserves, 63% were oil reserves.

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

On February 14, 2011, we acquired an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests surrounding the Mississippi River delta and a related gathering system (the ASOP Properties) from Anglo-Suisse Offshore Partners, LLC (ASOP) for \$200.7 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2011 (the ASOP Acquisition). As of December 31, 2010, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves. Of these proved developed reserves, 88% were oil reserves. The ASOP Acquisition was financed with the proceeds from the sale of \$210 million in aggregate principal amount of 8.25% senior notes due 2018 (the 8.25% Notes) offered to qualified institutional buyers pursuant to Rule 144A promulgated under the Securities Act of 1933, as amended (the Securities Act), and to persons outside the United States pursuant to Regulation S promulgated under the Securities Act. After deducting the initial purchasers' discount and estimated offering expenses, the Company realized net proceeds of approximately \$202 million.

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Competitive Strengths

High Quality Asset Base with Significant Exploitation and Exploration Potential. We believe our asset base is characterized by lower-risk properties that have predictable well control and production profiles. Our pro forma net proved reserves reflecting the ASOP Acquisition as of December 31, 2010 were 89% proved developed, which provides significant production visibility. Our fields offer significant development and exploration potential, with multiple producing zones and unexplored deeper horizons.

Oil-Weighted Reserves and Production. We believe we are more oil-focused in both our reserves and production as compared to many of our peers. After giving effect to the ASOP Acquisition, our pro forma net proved reserves at December 31, 2010 were approximately 68% oil, and our pro forma net average daily production for the quarter ended December 31, 2010 was 60% oil. Given the current commodity price environment and resulting disparity between oil and natural gas prices on a barrel of oil equivalent basis, we believe our high percentage of oil reserves compared to our overall reserve base provides us an economic advantage. Additionally, the production decline curve of oil is typically lower than a comparable natural gas decline curve, resulting in longer term production from current reserves.

Operating Control. After giving effect to the ASOP acquisition, we operate properties that contain approximately 80% of our proved reserves. As the operator of a property, we are afforded greater control of the optimization of production, the timing and amount of capital expenditures and the operating parameters and costs of our projects. As such, we are able to align capital expenditures with cash flow because we are generally able to adjust drilling plans in response to changes in commodity prices. Additionally, we believe that we are one of the lowest-cost operators in the region and are therefore able to maximize cash flows from our operated reserves.

Geographically Focused Properties in the Gulf of Mexico. We operate geographically focused properties located in the Gulf of Mexico shelf, which gives us the opportunity to minimize logistical costs and reduce staff. Our experience in the Gulf of Mexico, and particularly offshore Louisiana, has led us to focus our efforts in that particular region, where we are familiar with the fields, drilling and production trends and where we have amassed an extensive library of geologic information. We own an extensive high-quality 3-D seismic database that is primarily focused on our core area and currently covers approximately 11,700 square miles. This seismic data assists us in identifying attractive development and exploration drilling opportunities that adhere to our capital-efficient development strategies. We have recently reprocessed the 3-D seismic data covering our East Bay and South Timbalier 26 fields, and our initial evaluation indicates that this data will enable us to better image deeper prospective horizons below existing field pays as well as the shallower producing horizons. Drilling activity in the Gulf of Mexico shelf, as compared to deepwater drilling activities, has not been as severely impacted by the regulatory changes resulting from the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010. Over 26% of our developed net acreage is located in Louisiana state waters, which are not regulated by the Bureau of Ocean Energy Management, Regulation and Enforcement (the BOEMRE) and where there have been no delays in the permitting process for drilling.

Experienced Management and Significant Technical Expertise. We have an experienced and technically-adept management team, averaging more than 20 years of industry experience among our top seven executives. We have also built a strong technical staff of geologists and geophysicists, field operations managers and engineers to handle all aspects of our exploitation, exploration, production and decommissioning activities.

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Business Strategy

Pursue Capital Efficient Development in Core Areas. Our current producing asset base in the Gulf of Mexico shelf includes a large inventory of low-risk exploitation opportunities, as well as exploration prospects with multiple objectives and follow up opportunities. In 2010, we completed 19 workovers and drilled five sidetracks and five drill wells, with a 76% success rate. Our fiscal year 2011 capital budget is \$110 to \$125 million (excluding the cost of acquiring the ASOP properties), \$80 million of which is allocated to development of our existing Gulf of Mexico shelf asset base primarily in the East Bay and South Timbalier field areas, \$20 million of which is allocated to exploration projects and an additional \$10 million to \$25 million of which is allocated to development projects within the recently acquired ASOP Properties. We also plan to spend approximately \$17 million in 2011 on plugging, abandonment and other decommissioning activities. In our pre-acquisition fields, we will continue to focus on low-risk development projects, as well as a small number of high quality, high potential exploration prospects. We believe the ASOP Properties will enhance our exploitation strategy to increase production from legacy fields and will provide us with substantial incremental exploration opportunities within our core area.

Target Acquisition Opportunities to Replace Reserves and Leverage Operational Strengths. We continually review and monitor opportunities to acquire producing properties, leasehold acreage and drilling prospects in and around our core areas of operation so that we can act quickly as acquisition opportunities become available. We intend to focus our acquisition strategy on operated Gulf of Mexico shelf assets that are characterized by production-weighted reserves, seismic coverage and operated positions, while allowing us to maintain a conservative capital structure. We intend to use acquisitions of this type as a key method to replace and grow reserves and production, as we believe this strategy increases production and cash flow visibility while reducing dry hole and exploration risk. We believe our expertise in the Gulf of Mexico shelf and in plugging and abandonment operations allows us to effectively evaluate acquisitions and to operate the properties we eventually acquire.

Maintain Financial Discipline. We are committed to maintaining a conservative financial position, sufficient liquidity and a strong balance sheet. We have \$150.0 million available under our new \$250 million credit facility we entered into concurrently with the consummation of the ASOP Acquisition on February 14, 2011 (the new credit facility). In order to maintain financial flexibility, we generally plan to fund our initial 2011 fiscal year exploration and development capital budget entirely with cash flow from operations. Additionally, our operational control enables us to manage the timing of a substantial portion of our capital investments.

Retain Cost Leadership, with Continued Improvement. We emphasize identifying opportunities to reduce our costs in connection with our efforts to find, develop and produce our oil and natural gas reserves. We are one of the lowest cost operators among our public Gulf of Mexico peers, based on lease operating expense and general and administrative expense per Boe of production. We have reduced these costs per Boe by approximately 35% since 2008 by more efficiently allocating labor and transportation costs, reducing non-technical personnel and continuing our plugging, abandonment and decommissioning program to reduce lease operating expenses.

Capitalize on Competency in Plugging and Abandonment. We have established a proactive, multi-year plan to plug, abandon and decommission depleted wells and associated infrastructure. Gary Hanna, our chief executive officer who joined us in September 2009, has significant experience in conducting these types of operations and has supplemented our staff to accomplish this objective. With our core competency in plugging, abandonment and other decommissioning operations, we expect to reduce our lease operating expense 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

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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.

Properties

As of December 31, 2010, we had working interests in 19 producing fields located in the Gulf of Mexico shelf region, including larger legacy fields and smaller fields as follows:

our East Bay producing field on the southern flank of the Mississippi River delta;

three producing fields in the vicinity of the Bay Marchand salt dome (the Greater Bay Marchand area) and in close proximity to each other; and

15 smaller producing fields offshore Louisiana.

Our East Bay field comprised approximately 21% of our production during the year ended December 31, 2010 and 54% of our proved reserves at December 31, 2010. It is comprised of the South Pass 24 and 27 fields and is located 89 miles southeast of New Orleans, near the mouth of the Mississippi River. It contains 230 producing wells located along the coastline and in water depths ranging up to approximately 70 feet. We operate this field and own an average 97% working interest in our acreage position in this area. Our leasehold area covered 40,880 gross acres (39,586 net acres) as of December 31, 2010. During 2011, we plan to concentrate on exploitation opportunities in the East Bay field and to drill below 14,000 feet subsea using newly-reprocessed seismic data.

Our Greater Bay Marchand area comprised approximately 52% of our production during the year ended December 31, 2010 and 35% of our proved reserves at December 31, 2010. Our key assets in this area include the South Timbalier 26 and 41 fields and the Bay Marchand field located approximately 60 to 72 miles south of New Orleans in water depths of 73 feet or less. We own working interests ranging from 13% to 100% in the Greater Bay Marchand area. We operate the South Timbalier 26 and 41 blocks. During 2011, we plan to concentrate on exploitation opportunities in South Timbalier 26 with the benefit of newly-reprocessed seismic data.

The 15 smaller producing fields offshore Louisiana comprised approximately 16% of our production during the year ended December 31, 2010 and 8% of our proved reserves at December 31, 2010. These properties are located in water depths ranging from 18 to 225 feet with working interests ranging from 20% to 100%.

The ASOP Properties acquired on February 14, 2011 comprise three producing complexes located in the Gulf of Mexico shelf region offshore Louisiana surrounding the Mississippi River delta. The West Delta complex, a legacy producing area, comprised approximately 60% of the ASOP Properties' reserves at December 31, 2010 and is located 62 miles south, southeast of New Orleans. It contains 23 producing wells in water depths ranging from 29 to 87 feet and is comprised of five lease blocks. We operate the West Delta complex and own a working interest of 100% of the acreage position in this area. The South Pass complex

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comprised approximately 14% of the ASOP Properties reserves at December 31, 2010 and is located 96 miles southeast of New Orleans. It contains four producing wells in water depths of approximately 300 feet and is comprised of one field. The South Pass complex is operated by Energy XXI, and we own working interests ranging from 44% to 70% of the acreage position in this area. The Main Pass complex comprised approximately 26% of the ASOP Properties reserves at December 31, 2010 and is located 98 miles southeast of New Orleans. It contains 32 producing wells in water depths of approximately 250 feet and is comprised of two fields. The complex is operated by Apache, and we own a working interest of 33% of the acreage position in this area.

As of December 31, 2010, after giving effect to the ASOP Acquisition, we had an interest in 333 producing wells in 27 producing fields. These producing fields include three legacy operating areas. All of our properties, including the ASOP Properties, are predominantly located in the Gulf of Mexico shelf. This concentration facilitates our ability to manage the operated fields efficiently and provide economies of scale in our core operating area. In addition, the ASOP Properties complement our pre-acquisition reserve profile and increase our proved developed producing reserves, as well as the percentage of oil comprising our proved reserves. We believe there is significant exploitation and exploration potential with respect to the ASOP Properties that we can realize by leveraging our technical and operational expertise.

As of December 31, 2010, we also owned interests in 21 undeveloped blocks and one producing lease in the deepwater Gulf of Mexico area. These deepwater Gulf of Mexico properties comprised approximately 10% of our production during the year ended December 31, 2010 and 3% of our proved reserves at December 31, 2010. Our working interests in our leases in this area ranged from 15% to 33%. Our deepwater assets do not fit with our long-term strategy, and there are no current plans to develop these interests. As such, we may monetize or trade these assets.

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 20

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 adopted the provisions of the final rule in connection with the filing of our annual report for the year ended December 31, 2009.

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, 2010, 2009 and 2008. Our estimates of proved reserves are based on reserve reports prepared as of December 31, 2010 by Netherland, Sewell & Associates, Inc. (NSAI) and Ryder Scott Company, LP (Ryder Scott), independent petroleum engineers. Neither PV-10 nor the standardized measure of discounted future net cash flows shown in the table is intended to represent the current market value of the estimated oil and natural gas reserves that we own. Note 20 Supplementary Oil and Natural Gas Disclosures (Unaudited) 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.

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

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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.

	2010	As of December 31, 2009	2008
	(dollars in thousands)		
Total estimated net proved reserves (1):			
Oil (Mbbbls)	17,223	19,923	21,637
Natural gas (Mmcf)	61,251	67,378	90,808
Total (Mboe)	27,431	31,153	36,771
Net proved developed reserves (2):			
Oil (Mbbbls)	15,974	15,026	17,052
Natural gas (Mmcf)	56,410	57,139	79,413
Total (Mboe)	25,376	24,549	30,288
Net proved undeveloped reserves:			
Oil (Mbbbls)	1,249	4,897	4,585
Natural gas (Mmcf)	4,841	10,239	11,395
Total (Mboe)	2,055	6,604	6,483
Estimated future net revenues before income taxes (3)	\$ 565,922	\$ 534,771	\$ 557,660
Present value of estimated future net revenues before income taxes (PV-10) (3)(4)(6)	\$ 413,066	\$ 395,997	\$ 425,247
Standardized measure of discounted future net cash flows (5)(6)	\$ 359,458	\$ 393,802	\$ 416,171

- (1) The table does not include reserves associated with the ASOP Properties, which we acquired on February 14, 2011. As of December 31, 2010, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves. Of these proved developed reserves, 88% were oil reserves. All estimates of proved reserves with respect to the ASOP Properties contained in this Annual Report are based on reserve reports prepared as of December 31, 2010 by NSAI.
- (2) Net proved developed non-producing reserves as of December 31, 2010 (6,484 Mbbbls and 38,334 Mmcf) were 12,873 Mboe, or 47% of our total proved reserves.
- (3) The December 31, 2010 and 2009 amounts were calculated using oil prices of \$77.85 and \$57.70 per barrel, respectively, and natural gas prices of \$4.54 and \$3.96 per Mcf, respectively, held constant for the life of the reserves, computed in accordance with ASC 932, based on the unweighted, arithmetic 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.
- (4) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, determined in the manner described in footnote (3), discounted at a rate of 10% per year on a pre-tax basis.
- (5) 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.
- (6) PV-10 is 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.

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As of December 31, 2009, our proved undeveloped reserves (PUDs) totaled 4.9 Mmbbls of oil and 10,239 Mmcf of natural gas, for a total of 6.6 Mmboe. Included in these PUDs are 4.2 Mmboe 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. During 2010, we converted 0.3 Mmboe of PUDs to proved developed reserves. As a result of changes in our strategic focus during 2010 and the resulting reallocation of financial resources and technical personnel to higher potential organic and acquisition-related opportunities, including our ASOP Acquisition which closed on February 14, 2011, our plans and expectations have changed with respect to certain of the PUDs existing as of December 31, 2009. As a result, our PUDs as of December 31, 2010 reflect a decrease of approximately 4.3 Mmboe related to PUDs aged greater than five years for which funds were not committed in our 2011 development plan. We expect our remaining PUDs as of December 31, 2010 of 2.1 Mmboe to begin converting from proved undeveloped to proved developed as the planned development projects begin in 2011. Of the seven planned future development projects related to our PUDs, consisting of five sidetracks and two horizontal wells, three sidetracks and both horizontal wells are part of our committed 2011 development plan. The remaining two sidetracks are awaiting depletion of the current producing zone and are projected to occur in 2012. We project future development costs relating to the development of the PUDs remaining at December 31, 2010 to be approximately \$21.3 million in 2011, \$12.1 million in 2012, \$0.5 million in 2013, \$4.0 million in 2014, and \$2.5 million thereafter.

Our Vice President, Reserves, is the technical person primarily responsible for overseeing the preparation of our reserve estimates and for compliance with our policies. He is a registered petroleum engineer with extensive experience in reservoir analysis and reports directly to our executive management. At the end of each year, our reserve estimates are prepared by outside petroleum engineering firms. As of December 31, 2010, our estimates of proved reserves are based on reserve reports prepared by the independent petroleum engineering firms NSAI and Ryder Scott, both nationally recognized engineering firms.

We have internal controls in place to provide reasonable assurance of compliance with SEC rules in the determination of our reserve estimates. These controls include:

corporate policies which require reserve estimates to be in compliance with SEC guidelines;

data on new discoveries is reviewed by the Vice President, Reserves, and our outside engineering firms for evaluation and incorporation into our reserve estimates;

year-end reserve estimates are reviewed by our Vice President, Reserves, and our chief executive officer and other senior management; and

revisions are communicated to our Board of Directors.

The estimates of the oil and natural gas reserves of the ASOP Properties as of December 31, 2010 included in this Annual Report are based on reserve reports prepared by NSAI but were not subject to the internal controls summarized above.

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.

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The table below sets forth production information for each field that contains 15% or more of our total proved reserves as of December 31, 2010.

	Years Ended December 31,		
	2010	2009	2008
East Bay:			
Oil (Mbbbls)	1,031	837	885
Natural gas (Mmcf)	78	295	604
Total (Mboe)	1,044	886	986
South Timbalier 26:			
Oil (Mbbbls)	362	440	431
Natural gas (Mmcf)	1,167	1,394	815
Total (Mboe)	557	672	567

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.

	2010	Years Ended December 31, 2009	2008
		(In thousands)	
Acquisitions Proved	\$	\$	\$
Acquisitions Unproved	623	85	20,925
Exploration	31,463	2,477	56,202
Development (1)	25,643	8,815	127,948
Costs incurred	\$ 57,729	\$ 11,377	\$ 205,075

- (1) Includes asset retirement obligations incurred associated with finding, acquiring and developing our proved oil and natural gas reserves of \$0.1 million during the year ended December 31, 2010. 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, 2010.

	Total Productive Wells	
	Gross	Net
Oil	220	170
Natural gas	54	32
Total	274	202

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.

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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.

Acreage

The following table sets forth information relating to acreage held by us as of December 31, 2010. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
Gulf of Mexico Shelf	114,282	83,706
Deepwater Gulf of Mexico	5,760	1,600
Other	1,085	349
Total	121,127	85,655
Undeveloped:		
Gulf of Mexico Shelf	105,681	103,180
Deepwater Gulf of Mexico	115,200	30,303
Other	3,527	456
Total	224,408	133,939

We continually assess our undeveloped lease inventory for exploration opportunities and, where appropriate, develop strategies to maintain our inventory by allocating resources to such leases or arranging for the participation of others, including farm-outs and the use of prospect generation consulting geologists. We currently have no plans to continue developing strategic opportunities for leases covering 69% of the acreage expiring in 2011. As of December 31, 2010, the net book value of the leases expiring in 2011 and 2012 is \$0.6 million and \$0.4 million, respectively. Leases covering 28% of our undeveloped net acreage expire in 2011 (primarily deepwater and central and western Gulf of Mexico), 12% expire in 2012, 42% expire in 2013, 3% expire in 2014, 7% expire in 2015 and 8% expire thereafter.

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. During the year ended December 31, 2010, we completed 19 gross (16.2 net) recompletion operations of which 14 gross (11.2 net) were successful; 9 gross (6.4 net) exploratory drilling operations of which 7 gross (4.9 net) were successful; and 1 (gross and net) development well which was successful. 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's 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.

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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 ratable 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 (FERC) as a natural gas company under the NGA. We believe that our natural gas pipelines and appurtenant facilities meet the tests the FERC has historically used to establish a facility s status as a gathering facility not subject to regulation as a natural gas company under the NGA. However, the distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities is the subject of 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 facilities and operations may, at some point in the future, 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 a variety of safety, environmental, nondiscriminatory take, and common purchaser requirements, and complaint-based rate regulation.

The gathering systems are also subject to the jurisdiction of the BOEMRE, because they traverse the OCS pursuant to BOEMRE-issued easements. The BOEMRE 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 on a materially different basis 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

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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 under the NGA, as the owner and operator of these facilities, we may be subject to certain annual natural gas transaction reporting requirements and daily scheduled flow and capacity posting requirements imposed by FERC depending on the volume of natural gas transactions and flows on our facilities 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 Future Trading Commission ([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 purchased or sold 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 regularly proposes and implements 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

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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 in a materially different manner 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. In its policy statement on gas quality and interchangeability, the FERC encouraged all natural gas pipelines subject to its jurisdiction to use certain interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council (the NGC+ Work Group), as the common reference point for resolving gas quality and interchangeability issues. We do not believe that the adoption of gas quality and interchangeability standards that are in line with the NGC+ Work Group's interim guidelines by a pipeline that either directly or indirectly interconnects with our facilities would materially affect our operations. We cannot predict, however, whether FERC will approve 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 (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 Energy Policy Act of 2005 (EPAAct 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, EPAAct 2005 amended the NGA by increasing the criminal penalties available for violations of each Act. EPAAct 2005 also added a new section to the NGA that provides the FERC with the power to assess civil penalties of up to \$1,000,000 per day for violations of the NGA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce, including our Company. EPAAct 2005 also amended the NGA to add an anti-market manipulation provision that 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 EPAAct 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 entity. 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

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subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704 (as defined below) and daily scheduled flows. FERC's anti-market manipulation rule and enhanced civil penalty authority reflect a significant expansion of its enforcement authority.

FERC Market Transparency Rules. In 2007, the FERC issued a final rule on 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 actions on a materially different basis than other natural gas companies with whom we compete.

Environmental Matters

General. Various federal, state and local laws and regulations governing the protection of the environment, such as the Oil Pollution Act of 1990 (OPA), 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, including the management and disposal of drill production water and wastes;

limit or prohibit drilling and production activities on certain lands lying within wetlands and other protected areas and in ways that affect certain species;

impose permitting, monitoring, and recordkeeping requirements and other regulatory controls; and

impose substantial liabilities, including cleanup obligations, for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in the assessment of significant administrative, civil and criminal fines and penalties, the incurrence of capital expenditures, delays in the development of projects, the imposition of remedial or corrective action obligations, or injunctive relief that could include limitations on, or the cessation of, certain of our operations. Changes in environmental laws and regulations occur regularly and the current trend is toward more stringent environmental regulation and legislation. 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, the imposition of additional requirements in the future could materially adversely affect our operations and financial position and the oil and natural gas industry in general.

Oil Pollution Act of 1990. The OPA, and regulations thereunder, impose significant liability on responsible parties for removal costs and 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

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operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. OPA also requires that the lessee or permittee of the offshore area in which a covered offshore facility is located 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.

As a result of the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010, the U.S. Congress has considered legislation that could increase our obligations and potential liability under the OPA, including by eliminating the current cap on liability for damages and by increasing minimum levels of financial responsibility. OPA currently requires a minimum financial responsibility demonstration of \$35 million for companies operating in offshore waters, although the Secretary of Interior may increase this amount up to \$150 million in certain situations. At least one proposed bill would have imposed new requirements on OCS operations, including increasing the minimum level of financial responsibility to \$300.0 million. It is uncertain whether, and in what form, any such legislation will ultimately be adopted. 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.

Superfund. CERCLA, also known as Superfund, and comparable state laws impose 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. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances in the environment.

Under CERCLA, the term hazardous substance does not include petroleum, including crude oil or any fraction thereof, unless specifically listed or designated 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, we may generate waste that may fall within CERCLA's definition of a hazardous substance in the course of our ordinary operations. We also 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. 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.

Resource Conservation and Recovery Act. RCRA and comparable state laws impose detailed requirements relating to the handling, storage, treatment and disposal of hazardous waste. We routinely generate small quantities of hazardous waste in the ordinary course of our business that are subject to these requirements. These wastes are treated, stored and disposed of off-site at facilities that are permitted to manage them. 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

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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 current 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 petroleum, produced water and other certain wastes into navigable waters, including coastal 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, to a lesser degree, developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for significant civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants or unauthorized discharges of pollutants or fill material into wetlands or other waters. These statutes also impose liability for cleanup, restoration and damages on the parties responsible for those discharges for the costs of cleaning up any environmental damage caused by such 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, Migratory Bird Treaty Act, and Endangered Species Act. Certain federal laws, including the National Marine Sanctuary Act, the Marine Mammal Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated marine areas and marine species. These laws and their state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected plants and animals, including damage to their habitats. Further, if such 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.

In addition, 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, BOEMRE 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 BOEMRE also issues Notices to Lessees and Operators (NLTs) that provide guidance on the implementation of and compliance with Outer Continental Shelf Lands Act (OCSLA) regulations. The BOEMRE has issued numerous NLTs relating to the prevention of harm to marine species, with which we must comply.

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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 BOEMRE 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 limit the emissions of regulated pollutants from such equipment and, in some instances, require the installation and operation of pollution control equipment to achieve these emissions limitations and meet ambient air quality standards. These laws also require us to maintain operating permits for existing equipment and obtain 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 such 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 control laws and 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 United Nations Framework Convention on Climate Change, also known as 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 has considered legislation to reduce emissions of greenhouse gases; however, it is uncertain at this time whether, and in what form, such legislation will be adopted in the United States. Both President Obama and the Administrator of the EPA have expressed support for legislation to restrict or regulate emissions of greenhouse gases. In addition, several states, either individually or through multi-state regional initiatives, have already passed laws, adopted regulations or undertaken regulatory activity 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.

Even in the absence of federal legislation, the EPA has begun to regulate greenhouse gas emissions from both mobile and stationary sources. In 2009, the EPA published its finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. Thereafter, the EPA adopted a comprehensive national system for reporting emissions of greenhouse gases for major sources of emissions. On September 22, 2009, the EPA finalized a greenhouse gas reporting rule that requires large sources of greenhouse gas emissions to monitor, maintain records on, and annually report their greenhouse gas emissions. On November 8, 2010, the

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EPA also issued greenhouse gas monitoring and reporting regulations for petroleum and natural gas facilities, including offshore petroleum and natural gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year, that went into effect on December 30, 2010. The rule requires reporting of greenhouse gas emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. In 2010, the EPA also issued a final rule, known as the Tailoring Rule, that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act. The EPA's greenhouse gas rules are currently undergoing legal challenges and numerous other petitions are pending at the EPA from states and environmental groups seeking additional regulation of a variety of additional sources of greenhouse gas emissions. It is not possible at this time to predict what legislation or new regulations may be adopted to address greenhouse gas emissions or how the adoption of such legislation or regulations would impact our business. However, any new federal, regional or state restrictions on emissions of greenhouse gases 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.

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. Due to their location, our operations in the Gulf of Mexico are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems and our insurance may not cover all associated losses. 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.

Offshore Leasing and Permitting. The BOEMRE currently regulates offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Gulf of Mexico shelf, and removal of facilities. We believe that our operations are in material compliance with all applicable BOEMRE regulations and orders. On January 19, 2011, the U.S. Department of the Interior announced that it would divide offshore oil and gas responsibilities among three separate agencies, with the reorganization to be completed by October 1, 2011. The Department of Interior will create the Bureau of Ocean Energy Management with responsibility for leasing and environmental studies; the Bureau of Safety and Environmental Enforcement with responsibility for field operations, including inspections, regulatory compliance, and oil spill response; and a third agency for management of revenues. Once the reorganization is completed, the BOEMRE will cease to exist. At this time, we do not know the impact that this reorganization may have on our operations.

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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 BOEMRE and are required to comply with the regulations and orders promulgated by the BOEMRE under OCSLA.

The BOEMRE issued an NTL, effective October 15, 2010. The NTL imposes more stringent requirements for decommissioning facilities that pose a hazard to safety or the environment, as well as for facilities that are not useful for lease operations and that are not capable of oil and natural gas production in paying quantities. Historically, the BOEMRE granted approval to operators to maintain these structures in order to conduct future activities. However, the NTL significantly restricts this practice. Under the NTL, lessees must submit an application to permanently plug any well that poses a hazard to safety or the environment within 30 days after identifying the hazard. The NTL also imposes new deadlines for removing platforms or other facilities that are no longer useful for operations. Furthermore, the NTL imposes new deadlines for plugging, abandoning or performing downhole zonal isolation on wells that are no longer useful for operations and that are no longer capable of production in paying quantities. In January 2011, we responded to a written request from BOEMRE for information on our idle iron issues by submitting a company-wide three-year plan for our wellbore plugging and abandonment and decommissioning activities through 2013. This plan does not include the properties we have acquired from ASOP. In order to permit us to gather the necessary information and perform the necessary analysis with respect to these recently-acquired properties, BOEMRE has granted a 180-day extension for submitting an idle iron plan for these properties.

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 BOEMRE 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 BOEMRE issued guidance, through NTLs, 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 BOEMRE or successor agency, and these new requirements could increase our operating costs. The BOEMRE, its successors, 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 BOEMRE 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.

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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 2010, Shell Trading (US) Company accounted for approximately 42%, ConocoPhillips accounted for approximately 26% and Louis Dreyfus Energy Services, L.P. accounted for approximately 11%. 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, 2010, we had 100 full-time employees, including 18 geoscientists, engineers and technicians and 51 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. 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 administrative 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.

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Chapter 11 Reorganization

See Management's Discussion and Analysis of Financial Condition and Results of Operations Chapter 11 Reorganization for a description and discussion of our Chapter 11 reorganization in 2009.

Cautionary Statement Concerning Forward Looking Statements

This Annual Report contains forward-looking statements within the meaning of, and we intend that such forward-looking statements be subject to the safe harbor provisions of, the U.S. federal securities laws. Forward-looking statements are, by definition, statements that are not historical in nature and relate to possible future events. They may be, but are not necessarily, identified by words such as will, would, should, likely, estimates, thinks, strives, may, anticipates, expects, believes, intends, goals, plans, or projects and similar expressions.

These forward-looking statements reflect our current views with respect to possible future events, are based on various assumptions and are subject to risks and uncertainties. These forward-looking statements are not guarantees or predictions of our future performance, and our actual results and future developments may differ materially from those projected in, and contemplated by, the forward-looking statements. As a result, you should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in these forward-looking statements. Among the factors that could cause actual results to differ materially are the risks and uncertainties described under Part I, Item 1A, Risk Factors, including the following:

planned and unplanned capital expenditures;

adequacy of capital resources and liquidity including, but not limited to, access to additional capacity under our credit facility;

our substantial level of indebtedness;

our ability to incur additional indebtedness;

volatility in oil and natural gas prices;

volatility in the financial and credit markets;

changes in general economic conditions;

uncertainties in reserve and production estimates;

replacing our oil and natural gas reserves;

unanticipated recovery or production problems;

availability, cost and adequacy of insurance coverage;

hurricane and other weather-related interference with business operations;

drilling and operating risks;

production expense estimates;

the impact of derivative positions;

our ability to retain and motivate key executives and other necessary personnel;

availability of drilling and production equipment and field service providers;

the effects of delays in completion of, or shut-ins of, gas gathering systems, pipelines and processing facilities;

potential costs associated with complying with new or modified regulations promulgated by the BOEMRE;

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the impact of political and regulatory developments;

risks and liabilities associated with acquired properties or business, including the ASOP Properties;

our ability to make and integrate acquisitions, including the ASOP Properties;

oil and gas prices and competition; and

our ability to generate sufficient cash flow to meet our debt service and other obligations.

Many of these factors are beyond our ability to control or predict. Any, or a combination, of these factors could materially affect our future financial condition or results of operations and the ultimate accuracy of the forward-looking statements. These forward-looking statements are not guarantees of our future performance, and our actual results and future developments may differ materially from those projected in the forward-looking statements. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements.

For a further list and description of various risks, relevant factors and uncertainties that could cause future results or events to differ materially from those expressed or implied in our forward-looking statements, see **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. Given these risks and uncertainties, you should not place undue reliance on these forward-looking statements.

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 Related to Our Business**

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, including substantial capital expenditures for the acquisition, development, production, exploration and abandonment of oil and gas properties. Our business also requires substantial expenditures for routine maintenance. Our capital requirements will depend on numerous factors, and we cannot predict accurately the timing and amount of our capital requirements. Though we have the ability to borrow under our new credit facility, we intend to finance our development and exploration 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 our new credit facility may not be sufficient for our capital requirements not funded by cash flow from operations, and we may not be able to access additional financing resources for a variety of reasons, including restrictive covenants in our new credit facility. If we are unable to make scheduled payments on our new credit facility, or if our financing requirements are not met by our new 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.

Without additional capital resources, we may be forced to limit or defer our planned oil and natural gas exploration and development program and this will adversely affect the recoverability and ultimate value of our

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oil and natural gas properties, in turn negatively affecting our business, financial condition and results of operations. We may also be unable to obtain sufficient credit capacity with counterparties to finance the hedging of our future crude oil and natural gas production which may limit our ability to manage price risk. As a result, we may lack the capital necessary to complete potential acquisitions, obtain credit necessary to enter into derivative contracts to hedge our future crude oil and natural gas production or to capitalize on other business opportunities.

The borrowing base under our new credit facility is subject to re-determination and could be reduced in the future if commodity prices decline, which will limit our available funding for exploration and development.

Our current borrowing base under our new credit facility is \$150 million, and we currently have no amounts outstanding under our new credit facility. Our borrowing base is subject to semi-annual and certain other interim re-determinations by our lenders in their sole discretion. The next re-determination of the borrowing base is scheduled to occur on May 1, 2011. The lenders will re-determine the borrowing base based on an engineering report with respect to our oil and natural gas reserves, which will take into account the prevailing oil and natural gas prices at such time. Any reduction of the borrowing base is subject to approval of lenders holding not less than 66 2/3% of the lending commitments under our new credit facility.

In the future, we may not be able to access adequate funding under our new credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base re-determination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. If oil and natural gas commodity prices deteriorate, we anticipate that the revised borrowing base under our new credit facility may be reduced. As a result, we may be unable to obtain adequate funding under our new credit facility. If funding is not available when needed, it could adversely affect our exploration and development plans as currently anticipated and our ability to make new acquisitions, each of which could have a material adverse effect on our production, revenues and results of operations.

In addition, if there is a decrease in our borrowing base as a result of the outcome of a subsequent borrowing base re-determination and, as a result of such decrease, the outstanding borrowings under our new credit facility exceed the re-determined borrowing base, we will be required to repay such excess within 60 days. We may not have the financial resources in the future to make any mandatory principal prepayments required under our new credit facility.

Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under the notes.

We and the guarantors of the 8.25% Notes (the guarantors), on a consolidated basis, have outstanding approximately \$210.0 million of senior indebtedness, none of which is secured. Our substantial level of indebtedness could have significant effects on our business. For example, our level of indebtedness and the terms of our debt agreements may:

make it more difficult for us to satisfy our financial obligations under the 8.25% Notes, our other indebtedness and our contractual and commercial commitments and increase the risk that we may default on our debt obligations;

heighten our vulnerability to downturns in our business, our industry or in the general economy and restrict us from exploiting business opportunities or making acquisitions;

limit management's discretion in operating our business;

require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, and other general corporate purposes;

place us at a competitive disadvantage compared to our competitors that have less debt;

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limit our ability to borrow additional funds; and

limit our flexibility in planning for, or reacting to, changes in our business, the industry in which we operate or the general economy. Each of these factors may have a material and adverse effect on our financial condition and viability. Our ability to make payments with respect to the 8.25% Notes and to satisfy our other debt obligations will depend on our future operating performance, which will be affected by prevailing economic conditions and financial, business and other factors affecting our company and industry, many of which are beyond our control. In addition, the indenture governing the 8.25% Notes (the Indenture) and our new credit facility contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our failure to comply with those covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our debts.

Despite existing debt levels, we may still be able to incur substantially more debt, which would increase the risks associated with our leverage.

Even with our existing debt levels, we and our subsidiaries may be able to incur substantial amounts of additional debt in the future, including debt under our new and future credit facilities. As of December 31, 2010, after giving effect to the issuance of the 8.25% Notes and the ASOP Acquisition and entry into our new credit facility, we would have been able to incur approximately \$867.0 million of additional indebtedness permitted by the Indenture, including approximately \$150.0 million of debt under our new credit facility, and other permitted debt categories or baskets. In addition, the Indenture will allow us to issue additional notes under certain circumstances, which will also be guaranteed by the guarantors. Although the terms of the 8.25% Notes and our new and future credit facilities will limit our ability to incur additional debt, these terms do not and will not prohibit us from incurring substantial amounts of additional debt for specific purposes or under certain circumstances. If new debt is added to our and our subsidiaries' current debt levels, the related risks that we and they now face could intensify and could further exacerbate the risks associated with our leverage.

Our new credit facility and the Indenture impose significant operating and financial restrictions on us and our subsidiaries that may prevent us from pursuing certain business opportunities and restrict our ability to operate our business.

Our new credit facility and the Indenture contain covenants that restrict our and our restricted subsidiaries' or, in the case of the new credit facility, our and all of our subsidiaries' ability to take various actions, such as:

transferring or selling assets;

paying dividends or distributions, buying subordinated indebtedness or securities, making certain investments or making other restricted payments;

incurring or guaranteeing additional indebtedness or, in the case of the Indenture and only with respect to our restricted subsidiaries, issuing preferred stock;

creating or incurring liens;

incurring dividend or other payment restrictions affecting restricted subsidiaries;

consummating a merger, consolidation or sale of all or substantially all our assets;

entering into transactions with affiliates;

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engaging in business other than a business that is the same or similar to our current business or a reasonably related extension thereof;

making capital expenditures;

issuing capital stock of certain subsidiaries;

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entering into sale/leaseback transactions;

making acquisitions or investments; and

designating subsidiaries as unrestricted subsidiaries.

In addition, our new credit facility restricts us from entering into certain hedging contracts or extending credit. Our new credit facility also requires, and any future credit facilities may additionally require, us to comply with specified financial ratios, including regarding interest coverage, total leverage, current assets to current liabilities or other similar ratios.

We may also be prevented from taking advantage of business opportunities that arise if we fail to meet certain ratios or because of the limitations imposed on us by the restrictive covenants under these agreements. The restrictions contained in our new credit facility and the Indenture may also limit our ability to plan for or react to market conditions, meet capital needs or otherwise restrict our activities or business plans and adversely affect our ability to finance our operations, enter into acquisitions, execute our business strategy, effectively compete with companies that are not similarly restricted or engage in other business activities that would be in our interest. In the future, we may also incur debt obligations that might subject us to additional and different restrictive covenants that could affect our financial and operational flexibility. We cannot assure you that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on acceptable terms or at all should we seek to do so.

Our ability to comply with these covenants will likely be affected by events beyond our control, and we cannot assure you that we will satisfy those requirements. A breach of any of these provisions could result in a default under our new credit facility, the Indenture or any future credit facilities we may enter into, which could allow all amounts outstanding thereunder to be declared immediately due and payable, subject to the terms and conditions of the documents governing such indebtedness. If we were unable to repay the accelerated amounts, our secured lenders could proceed against the collateral granted to them to secure such indebtedness. This would likely in turn trigger cross-acceleration and cross-default rights under any other credit facilities and indentures, if any then exist governing the 8.25% Notes and the terms of our other indebtedness outstanding at such time. If the amounts outstanding under our new credit facility, the 8.25% Notes or any other indebtedness outstanding at such time were to be accelerated or were the subject of foreclosure actions, we cannot assure you that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders.

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;

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

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 mitigate the impact of natural reservoir declines on 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 experience a decline in our revenues and available capital, which would likely substantially decrease our capital expenditures, drilling activities and operations.

Any continuing volatility in the financial and credit markets 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.

The recent credit crisis and related turmoil in the global financial systems have had an impact on our business and our financial condition, and we may face challenges if economic and financial market conditions do not improve. Historically, we have used our cash flow from operations and borrowings under our credit facility to fund our capital expenditures and have relied on the capital markets to provide us with additional capital for large or exceptional transactions. A continuation or recurrence of the economic crisis could further reduce the demand for oil and natural gas and put downward pressure on the prices for oil and natural gas.

In the future, we may not be able to access adequate funding under our new credit facility and any other debt instruments we may enter into as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base re-determination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Declines in commodity prices, or a continuing decline in those prices, could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base.

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 our plan of reorganization, financial information included in this Annual Report for periods prior to September 30, 2009 are not comparable with our financial information for periods on or after September 30, 2009.

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 were adjusted to reflect fair value as of September 30, 2009. In addition to fresh-start accounting, our financial statements reflect the effects of all of the transactions implemented by our plan of reorganization. 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

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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 current operations and a significant part of the value of our production and reserves are concentrated in the Gulf of Mexico. 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.

Fifty-two percent of our net daily production came from our South Timbalier and other Greater Bay Marchand area properties for the year ended December 31, 2010 and approximately 35% of our proved reserves at December 31, 2010 were located in the fields that comprise this area. In addition, 21% of our net daily production for the year ended December 31, 2010 came from our East Bay field and approximately 54% of our proved reserves at December 31, 2010 were located in this area. After giving effect to the ASOP Acquisition, 58% of our pro forma net daily production for the year ended December 31, 2010 and 68% of our pro forma proved reserves at December 31, 2010 were attributable to these areas. 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.

The relatively steep decline curves generally associated with oil and gas properties located in the Gulf of Mexico 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, 2010, our independent petroleum engineers estimate that, on average, 66% of our total proved reserves will be produced within five years. We will have to continue to develop, exploit, find or acquire additional reserves to sustain our current production levels and to grow our production.

We may not be able to keep pace with technological developments in our industry.

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial costs. In addition, other natural gas and oil companies may have greater financial,

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technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition, and results of operations could be materially adversely affected.

With respect to a portion of our properties, we are not the operator and therefore are not in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves on such properties.

As we carry out our planned drilling program, we will not serve as operator of all planned wells. As of December 31, 2010, we operated approximately 86% of our properties, based on proved reserves at December 31, 2010. Following the ASOP Acquisition, we operate approximately 80% of our properties, including the ASOP Properties, based on proved reserves at December 31, 2010. As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

the timing and amount of capital expenditures;

the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;

the operator's expertise and financial resources;

approval of other participants in drilling wells;

selection of technology; and

the rate of production of the reserves.

Our operations in the deepwater Gulf of Mexico area present unique operating risks.

The deepwater Gulf of Mexico area 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. Because we have operations in the deepwater Gulf of Mexico area, we are exposed to these risks. Our deepwater assets do not fit within our long-term strategy, and there are no current plans to develop these interests. As such, we may monetize or trade these assets. However, there is no assurance that we will be able to divest these interests on terms acceptable to us.

If we place hedges on future production and encounter difficulties meeting that production, we may not realize the originally anticipated cash flows.

Our assets consist of a mix of reserves, with some being developed while others are undeveloped. To the extent that we sell the production of these reserves on a forward-looking basis but do not realize that anticipated level of production, our cash flow may be adversely affected if energy prices rise above the prices for the forward-looking sales. In this case, we would be required to make payments to the purchaser of the forward-looking sale equal to the difference between the current commodity price and that in the sales contract multiplied by the physical volume of the shortfall. There is the risk that production estimates could be inaccurate or that storms or other unanticipated problems could cause the production to be less than the amount anticipated, causing us to make payments to the purchasers pursuant to the terms of the hedging contracts.

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Our price risk management activities could result in financial losses or could reduce our income, which may adversely affect our cash flows.

We enter into derivative contracts to reduce the impact of natural gas and oil price volatility on our cash flow from operations. Currently, we use a combination of natural gas and crude oil put and swap arrangements to mitigate the volatility of future natural gas and oil prices received.

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

a counterparty may not perform its obligation under the applicable derivative instrument;

there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and

the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

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 business will also be dependent upon our ability to attract and retain qualified personnel. Acquiring and keeping qualified personnel could prove more difficult or cost substantially more than estimated. This could cause us to incur greater costs, or prevent us from pursuing our strategy as quickly as we would otherwise wish to do.

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.

Risks Related to Our Acquisition Strategy

Our acquisition strategy involves potential risks that could adversely impact our future financial performance.

A significant component of our business strategy is to acquire oil and gas properties. Acquisitions of producing properties from third parties require us to assess many factors that are inherently inexact and may be inaccurate, including:

the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;

the risk that financial information relating to the acquired assets may not be accurate;

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inaccurate assumptions about revenues and costs, including synergies;

significant increases in our indebtedness and working capital requirements;

an inability to transition and integrate successfully or timely the businesses we acquire;

the cost of transition and integration of data systems and processes;

potential environmental problems and costs;

the assumption of unknown liabilities;

limitations on rights to indemnity from the seller;

the diversion of management's attention from other business concerns;

increased demands on existing personnel and on our corporate structure;

increased responsibility for plugging and abandonment costs;

customer or key employee losses of the acquired businesses; and

the failure to realize expected growth or profitability.

The scope and cost of these risks may ultimately be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely impact our future financial performance and ability to pay principal and interest on the notes. Future transactions may prove to stretch our internal resources and infrastructure. As a result, we may need to hire additional personnel and invest in additional resources, which will increase our costs. Any further acquisitions we make over the short term would likely exacerbate these risks.

We may record material impairments to the carrying values of our oil and natural gas properties if oil and gas prices decline from prices we used to estimate the acquisition fair values of acquired oil and gas properties.

We record acquisitions of oil and natural gas properties, including the ASOP Acquisition, using the purchase method of accounting which requires that we record the acquired oil and natural gas properties at their fair values as of the acquisition date. We may be required to recognize material non-cash impairment charges in future reporting periods if market prices for oil or natural gas decline and, as a result, the estimated fair values of the acquired oil and natural gas properties decline from the values estimated as of the acquisition date.

We may be unable to successfully integrate the operations of the properties we acquire.

Integration of the operations of the properties we acquire with our existing business will be a complex, time-consuming and costly process. Failure to successfully integrate the acquired businesses and operations in a timely manner may have a material adverse effect on our business, financial condition, results of operations and cash flows. The difficulties of combining the acquired operations include, among other things:

operating a significantly larger combined organization;

integrating corporate, technological and administrative functions;

integrating internal controls and other corporate governance matters;

diverting management's attention from other business concerns;

loss of key vendors from the acquired businesses;

a significant increase in our indebtedness; and

potential environmental or regulatory liabilities and title problems.

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The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. Our operating performance, revenues and costs could be materially adversely affected if:

we are not successful in completing the integration of acquired properties into our operations;

the integration takes longer or is more complex than anticipated; or

we cannot operate acquired properties as effectively as we anticipate.

We may not realize all of the anticipated benefits from our acquisitions.

We may not realize all of the anticipated benefits from any future acquisitions, such as increased earnings, cost savings and revenue enhancements, for various reasons, including difficulties integrating operations and personnel, higher than expected acquisition and operating costs or other difficulties, unknown liabilities, inaccurate reserve estimates and fluctuations in market prices.

We may not have fully identified liabilities associated with properties or assets we acquire or obtained adequate protection from sellers against liabilities.

Our assessments of potential acquisitions may not reveal all existing or potential problems with the subject properties or permit 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 inspect every well, platform or pipeline. Our inspections may not identify structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume 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. As a result, we may not realize all of the anticipated benefits from future acquisitions, such as increased earnings, cost savings and revenue enhancements.

The properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the acquired properties or obtain protection from sellers against such liabilities.

The properties we acquire may not produce as expected, may be in an unexpected condition and we may be subject to increased costs and liabilities, including environmental liabilities. Although we review properties prior to acquisition in a manner consistent with industry practices, such reviews are not capable of identifying all potential adverse conditions. Furthermore, we have not yet been able to subject the preparation of reserve estimates for acquired properties to the same internal controls we have for the preparation of reserve estimates for our existing properties. Generally, it is not feasible to review in depth every individual property involved in each acquisition. We focus our review efforts on the higher-value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties and preparation of reserve reports in accordance with our internal controls may not necessarily reveal existing or potential problems or permit a buyer to become sufficiently familiar with the properties to fully assess their condition, any deficiencies, and development potential.

If we are unable to execute our acquisition strategy successfully, our business may not continue to grow.

We intend to pursue opportunistic acquisitions that leverage our organizational strengths. However, we may not be able to identify and consummate future acquisitions successfully, and assets that we do acquire may not yield anticipated benefits. Our failure to execute our acquisition strategy successfully in the future could limit our ability to continue to grow our business.

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Risks Related to Our Industry

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. 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 in the future may depend 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.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves.

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 unweighted, arithmetic average of the closing price on the first day of each of the twelve months during the preceding fiscal year and costs as of the date of the estimate held constant for the life of the reserves. However, actual future net cash flows from our natural gas and oil properties will be affected by factors such as:

the volume, pricing and duration of our natural gas and oil hedging contracts;

supply of and demand for natural gas and oil;

actual prices we receive for natural gas and oil;

our actual operating costs in producing natural gas and oil;

the amount and timing of our capital expenditures and decommissioning costs;

the amount and timing of actual production; and

changes in governmental regulations or taxation.

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The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating

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discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our estimates of proved reserves and related PV-10 and standardized measure of discounted future net cash flows have been prepared in accordance with new SEC rules, which went into effect for fiscal years ending on or after December 31, 2009, and may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This Annual Report presents estimates of our proved reserves and related PV-10 as of December 31, 2010 and 2009 and standardized measure of discounted future net cash flows as of December 31, 2010 and 2009, all of which have been prepared and presented under new SEC rules. These new rules are effective for fiscal years ending on or after December 31, 2009, and require companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing. The previous rules required that reserve estimates be calculated using year-end pricing. As a result of these changes, and because the new rules do not have a retroactive effect to periods that ended prior to December 31, 2009, direct comparisons to our prior period reserves amounts may be more difficult.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our future proved undeveloped reserves if we do not drill and develop those reserves within the required five-year timeframe.

The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, the estimates of our proved reserves for any periods ending on or after December 31, 2009 included in this Annual Report could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance. On December 30, 2010, the SEC provided comments on the periodic filings we made with the SEC in 2010. These comments included comments on certain of our reserve disclosures, and we are in the process of responding to these comments. We do not believe that these comments will result in material changes to the reserve disclosures we have previously made.

We may be limited in our ability to book additional proved undeveloped reserves under recent SEC rules.

We have included in this Annual Report certain estimates of our and the ASOP Properties' proved reserves as of December 31, 2010 prepared in a manner consistent with our and our independent petroleum engineer's interpretation of the recent SEC rules relating to modernizing reserve estimation and disclosure requirements for oil and natural gas companies. These recent rules were effective for annual reporting periods ended on or after December 31, 2009. Included within these recent SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Further, if we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may be required to write-off reserves previously recognized as proved undeveloped. Also, since we have acquired the ASOP Properties very recently, we do not have a development plan for these properties and there cannot be any assurance as to what level of proved undeveloped reserves will be supported by the plan we do develop. As of December 31, 2010, approximately 7% of our total proved reserves were undeveloped, and approximately 47% of our total proved reserves were developed non-producing reserves. As of December 31, 2010, approximately 24% of the ASOP Properties' total proved reserves were undeveloped, and approximately 15% of the ASOP Properties' total proved reserves were developed non-producing reserves. There can be no assurance that all of those reserves will ultimately be developed or produced.

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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. Though our 2011 fiscal year capital budget contemplates the deployment of a significantly larger amount of capital compared to the capital expenditures in 2010, which were at levels significantly lower than our historical average, there can be no assurance that we will be able to grow production through the drill-bit at rates we have experienced in the past. Though we intend to pursue development and acquisition opportunities, there is no assurance that our efforts will yield their intended results. 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.

Unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We may become responsible for unanticipated costs associated with abandoning and reclaiming wells, facilities and pipelines. Abandonment and reclamation of facilities and the costs associated therewith are often referred to as decommissioning. Should decommissioning be required that is not presently anticipated, or should the decommissioning be accelerated (such as can happen after a hurricane), these costs may exceed the value of reserves remaining at any particular time. We may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy these decommissioning costs could have a material adverse effect on our financial position and results of operations.

We may not be insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance coverage against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties from operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third party liability, workers compensation and employers liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages and losses.

Currently, we have general liability insurance coverage with an annual aggregate limit of \$2.0 million and umbrella liability coverage with an aggregate limit of \$150.0 million applicable to our working interest. We also have an offshore property physical damage policy that contains a \$70.0 million annual aggregate named windstorm limit. Our operational control of well coverage provides limits that vary by well location and depth and range from a combined single limit of \$20.0 million to \$75.0 million per occurrence. Deepwater wells have a coverage limit of \$50.0 million per occurrence. Additionally, we maintain \$70.0 million in oil pollution liability coverage. Our control of well and oil pollution liability policy limits are scaled proportionately to our working interests, except for our deepwater control of well coverage, which limit is to our working interest and all of our policies described above are subject to deductibles, sub-limits and/or self-insurance. Under our service agreements, including drilling contracts, generally we are indemnified for injuries and death of the service provider's employees as well as contractors and subcontractors hired by the service provider.

An operational or hurricane related event may cause damage or liability in excess of our coverage, which might severely impact our financial position. We may be liable for damages from an event relating to a project in which we are a non-operator, but have a working interest in such project. Such an event may also cause a significant interruption to our business, which might also severely impact our financial position. For example, we experienced production interruptions in 2005, 2006 and 2007 from Hurricanes Katrina and Rita and in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance.

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We reevaluate the purchase of insurance, policy limits and terms annually each April. In light of the recent catastrophic accident in the Gulf of Mexico, we may not be able to secure similar coverage for the same costs. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations in the Gulf of Mexico, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect 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;

blow-outs and surface cratering;

mechanical difficulties and pipe, cement, sub-sea well or pipeline failures;

fires and explosions;

personal injuries and death; and

natural disasters, especially hurricanes and tropical storms in the Gulf of Mexico region.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses because of costs and/or liability incurred as a result of:

injury or loss of life;

severe damage to and destruction of property, natural resources and equipment;

pollution and other environmental damage;

clean-up responsibilities;

regulatory investigations and penalties;

suspension of our operations; and

repairs to resume operations.

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

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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 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.

If we are unable to effectively manage the commodity price risk of our production if energy prices fall, we may not realize the anticipated cash flows from our acquisitions.

Compared to some other participants in the oil and gas industry, we are a relatively small company with modest resources. Therefore, there is the possibility that we may be unable to find counterparties willing to enter into derivative arrangements with us or be required to either purchase relatively expensive put options, or commit to deliver future production, to manage the commodity price risk of our future production. To the extent that we commit to deliver future production, we may be forced to make cash deposits available to counterparties as they mark to market these financial hedges. Proposed changes in regulations affecting derivatives may further limit or raise the cost, or increase the credit support required to hedge. This funding requirement may limit the level of commodity price risk management that we are prudently able to complete. In addition, we are unlikely to hedge undeveloped reserves to the same extent that we hedge the anticipated production from proved developed reserves. If we fail to manage the commodity price risk of our production and energy prices fall, we may not be able to realize the cash flows from our assets that are currently anticipated even if we are successful in increasing the production and ultimate recovery of reserves.

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 and 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. Redeployment of drilling rigs to areas other than the Gulf of Mexico in the wake of the Deepwater Horizon incident in April 2010, discussed below, may reduce the availability of offshore rigs, which could increase costs in future years.

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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. In deepwater operations, market access depends on the proximity of, and our ability to tie into, existing production platforms owned or operated by third parties and the ability to negotiate commercially satisfactory arrangements with the owners or operators. 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, 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 production could be limited or delayed and our revenues could be adversely affected.

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 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.

The recent explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico and the resulting oil spill may significantly increase our risks, costs and delays.

The recent explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico and the resulting oil spill may significantly impact the risks we face. The Deepwater Horizon incident and resulting legislative, regulatory and enforcement changes, including increased tort liability, could increase our liability that may arise if any incidents occur on our offshore operations. We cannot predict the ultimate impact the Deepwater Horizon incident and resulting changes in regulation of offshore oil and natural gas operations will have on us.

In response to the spill, and during a moratorium on deepwater (below 500 feet) drilling activities implemented between May 30, 2010 and October 12, 2010, the BOEMRE issued a series of NTLs and adopted changes to its regulations to impose a variety of new measures intended to help prevent a similar disaster in the future.

Offshore operators, including those operating in deepwater, outer continental shelf waters and shallow waters, where we have substantial operations, must now comply with strict new safety and operating requirements. For example, before being allowed to resume drilling, outer continental shelf operators must certify compliance with all applicable operating regulations found in 30 C.F.R. Part 250, including those rules recently placed into effect, such as rules relating to well casing and cementing, blowout preventers, safety certification, emergency response, and worker training. Operators of all offshore waters also must demonstrate the availability of adequate spill response and blowout containment resources. Notwithstanding the lifting of the moratorium on October 12, 2010, we cannot predict with certainty when new permits will be granted under the

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new requirements. We anticipate that there will continue to be delays in the resumption of drilling-related activities, including delays in the issuance of drilling permits, as these regulatory initiatives are fully implemented.

Legislative and regulatory initiatives relating to offshore operations, which include consideration of increases in the minimum levels of demonstrated financial responsibility required to conduct exploration and production operations on the outer continental shelf and elimination of liability limitations on damages, will, if adopted, likely result in increased costs and additional operating restrictions and could have a material adverse effect on our business.

In addition to the new requirements recently imposed by the BOEMRE, there have been a variety of proposals to change existing laws and regulations that could materially adversely affect our operations and cause us to incur substantial costs, including by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory burdens. Furthermore, such proposed changes could lead to a wide variety of other unforeseeable consequences that make operations in the Gulf of Mexico and other offshore waters more difficult, more time consuming, and more costly. For example, the U.S. Congress recently considered amendments to OPA, in response to the Deepwater Horizon incident. OPA and regulations adopted pursuant to OPA impose liabilities for and requirements related to oil spills into waters of the United States, including the outer continental shelf waters where we have substantial operations. OPA subjects operators of offshore leases and owners and operators of oil handling facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from an oil spill, including, but not limited to, the costs of responding to a spill, natural resource damages and economic damages suffered by persons adversely affected by the spill. The U.S. Congress has considered legislation that would eliminate existing liability caps for damages under OPA. OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. OPA currently requires a minimum financial responsibility demonstration of \$35.0 million for companies operating in offshore waters, although the Secretary of Interior may increase this amount up to \$150.0 million in certain situations. Congress considered one proposed bill with regard to OPA that would, if adopted, impose new requirements on OCS operations, including increasing the minimum level of financial responsibility to \$300.0 million. If OPA is amended to materially increase the minimum level of financial responsibility beyond current requirements, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. If we are unable to provide the level of financial assurance required by OPA, we may be forced to sell our properties or operations located in offshore waters or enter into partnerships with other companies that can meet the increased financial responsibility requirement, and any such developments could have an adverse effect on the value of our offshore assets and the results of our operations. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating in offshore waters will be increased.

We do not know how the ongoing reorganization of the BOEMRE will impact potential future regulations or enforcement that may affect our operations.

On May 19, 2010, the U.S. Department of the Interior announced that it would reorganize the Minerals Management Service by dividing its offshore oil and gas responsibilities among three separate agencies. Shortly thereafter, on June 18, 2010, the Minerals Management Service was renamed the Bureau of Ocean Energy Management, Regulation and Enforcement, or BOEMRE. The BOEMRE currently regulates offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Gulf of Mexico shelf and removal of facilities. On October 1, 2010, the first phase of reorganization took place when the revenue collection arm of the former Mineral Management Service became the Office of Natural Resources Revenue. On January 19, 2011, the U.S. Department of the Interior announced the structures and responsibilities of the two remaining agencies, with the reorganization of the BOEMRE into these agencies to be completed by October 1, 2011. Interior will create the Bureau of Ocean Energy Management, which will have responsibility for leasing and environmental studies, and the Bureau of

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Safety and Environmental Enforcement, which will have responsibility for field operations, including inspections, regulatory compliance, and oil spill response. Once the reorganization is completed, the BOEMRE will cease to exist. At this time, we cannot predict the impact that this reorganization, or future regulations or enforcement actions taken by the new agencies, may have on our operations.

We may need to obtain bonds or other surety in order to maintain compliance with regulations promulgated by the BOEMRE, which, if required, could be costly and reduce borrowings available under our new credit facility or any other credit facilities we may enter into in the future.

The BOEMRE regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the outer continental shelf of the Gulf of Mexico and removal of facilities. The BOEMRE generally requires that lessees have substantial net worth or post bonds or other acceptable assurances so that the various obligations of lessees on the Gulf of Mexico shelf will be met. While we believe that we are currently exempt from the supplemental bonding requirements of the BOEMRE, the BOEMRE could re-evaluate our plugging obligations and increase them which could cause us to lose our exemption. The cost of these bonds or other surety could be substantial and there is no assurance that bonds or other surety could be obtained in all cases. In addition, we may be required to provide letters of credit to support the issuance of these bonds or other surety. Such letters of credit would likely be issued under our new credit facility or another credit facility we may enter into in the future and would reduce the amount of borrowings available under such facility in the amount of any such letter of credit obligations. The cost of compliance with these supplemental bonding requirements could materially and adversely affect our financial condition, cash flows and results of operations.

We are subject to extensive governmental laws and regulations, including environmental regulations and permit requirements, 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.

The construction and operation of our projects also require numerous permits and approvals from governmental agencies. If we are unable to acquire or renew permits and approvals required for operations, we may be forced to suspend or cease operations altogether. We may not be able to obtain all necessary permits and approvals, and as a result our operations may be adversely affected. In addition, obtaining all necessary permits and approvals may necessitate substantial expenditures and may create a risk of expensive delays or loss of value if a project is unable to proceed as planned due to changing requirements or local opposition.

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 Business Environmental Matters.

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.

There are state, national and international efforts to regulate the emission of greenhouse gases including, most significantly, carbon dioxide. The U.S. Congress has considered legislation that seeks to control or reduce emissions of greenhouse gases from a variety of sources. In addition, several states have already taken legal

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measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories or regional cap-and-trade programs. It is uncertain at this time whether, and in what form, climate change legislation will ultimately be adopted in the United States.

The EPA has started to implement regulations pertaining to greenhouse gas emissions. In 2009, the EPA issued a finding under section 202(a) of the Clean Air Act, concluding that greenhouse gas pollution endangers the public health and welfare of current and future generations and the EPA finalized a greenhouse gas emission standard for mobile sources. On September 22, 2009, the EPA finalized a greenhouse gas reporting rule that requires large sources of greenhouse gas emissions to monitor, maintain records on and annually report their greenhouse gas emissions. On November 8, 2010, the EPA also issued greenhouse gas monitoring and reporting regulations specifically for petroleum and natural gas facilities, including offshore petroleum and natural gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of greenhouse gas emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. The EPA issued a final rule that makes certain stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions, beginning in 2011, under the Clean Air Act. Several of the EPA's greenhouse gas rules are being challenged in pending court proceedings and, depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

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.

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 regulation by the FERC, but FERC regulations still affect our non-FERC jurisdictional businesses and the markets for products derived from these businesses. The FERC issued Order 704, which requires 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.

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. We believe that our natural gas gathering facilities 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 facilities and federally unregulated gathering facilities is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC or the courts.

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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 or the courts.

The BOEMRE 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 BOEMRE granted approval to operators to maintain such facilities in order to conduct other future activities. However, we expect that this practice will be more limited in the future. The BOEMRE has stated that these measures are in response to recent hurricane seasons in which idle structures were damaged or destroyed. We recently responded to a BOEMRE 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 periodically review our plans with the BOEMRE to perform wellbore plugging and abandonment and decommissioning work on certain facilities and structures in our East Bay field.

The BOEMRE 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 EPCRA of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to \$1.0 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's civil penalty authority may apply to a broad range of market participants that have not historically been subject to its regulations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to annual reporting requirements. Additional rules and regulations that impact our facilities and operations 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.

Our sales of oil and natural gas, and any hedging activities related to such energy commodities, expose us to potential regulatory risks.

The FERC, the Federal Trade Commission and the CFTC, hold statutory authority to monitor certain segments of the physical and futures energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil and natural gas, and any hedging activities related to these energy commodities, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority.

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Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect our financial condition or results of operations.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

The U.S. Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material effect on our financial condition and our results of operations.

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.

To date, none of these proposals has been enacted. However, should any of these proposals be enacted, our taxes may 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 been voted on or become law, we do not know the ultimate impact any of these proposals may have on our business.

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.

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Item 1B. *Unresolved Staff Comments*

None.

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.

Table of Contents**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		
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	12.35	8.28
Second Quarter	14.62	11.36
Third Quarter	13.22	9.61
Fourth Quarter	15.00	10.75
2011		
First Quarter (through February 25, 2011)	16.38	13.95

On February 25, 2011, the last reported sales price of our common stock on the NYSE was \$16.38 per share.

As of February 25, 2011, there were approximately 151 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 our new credit facility and the Indenture related to our 8.25% 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.

Table of Contents**Securities Authorized for Issuance under Equity Compensation Plans**

The following table provides information as of December 31, 2010 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)	509,986	\$ 10.49	630,737
Total	509,986	\$ 10.49	630,737

(1) Comprised of 488,616 shares subject to issuance upon the exercise of options and 21,370 shares which will vest 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 exercise price of options.

(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.

Table of Contents**Item 6. Selected Financial Data**

The following table shows selected financial data derived from our consolidated financial statements, which are set forth in Part II, Item 8, Financial Statements and Supplementary Data of this Annual Report. The data should be read in conjunction with Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report.

	Successor Company		Period from January 1, 2009 through September 30, 2009	Predecessor Company (1) Years Ended December 31,		
	Year Ended December 31, 2010	Period from October 1, 2009 through December 31, 2009		2008	2007 (2)	2006
(In thousands, except per share data)						
Statement of Operations Data:						
Revenue	\$ 239,909	\$ 56,750	\$ 134,885	\$ 356,252	\$ 454,649	\$ 449,550
Income (loss) from operations (3)	7,309	(4,523)	(51,323)	(25,531)	(56,013)	(55,343)
Net loss	(8,468)	(21,012)	(36,114)	(52,212)	(79,955)	(50,400)
Basic and diluted loss per common share	\$ (0.21)	\$ (0.53)	\$ (1.12)	\$ (1.63)	\$ (2.32)	\$ (1.32)

	Successor Company As of		2008	Predecessor Company (1) As of December 31,	
	December 31, 2010	December 31, 2009		2007 (2)	2006
(In thousands)					
Balance Sheet Data:					
Total assets	\$ 626,906	\$ 709,228	\$ 766,766	\$ 814,856	\$ 1,003,845
Long-term debt, excluding current maturities (4)		58,590		484,501	317,000
Stockholders' equity	473,116	480,087	57,119	101,970	372,269
Cash dividends per common share					

- (1) In connection with our emergence from Chapter 11 reorganization, 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.
- (2) Amounts in 2007 reflect the sale of substantially all of our onshore South Louisiana assets in June 2007.
- (3) The loss from operations in 2008, 2007 and 2006 includes business interruption insurance recoveries of \$4.2 million, \$9.1 million and \$32.9 million, respectively, from deferred production at our covered fields resulting from Hurricanes Gustav and Ike in 2008 and Katrina and Rita in 2005.
- (4) Long-term debt classified as current was \$18.8 million and \$497.5 million at December 31, 2009 and 2008, respectively. At December 31, 2007 and 2006, none of our debt was classified as current. At December 31, 2010, we had no borrowings outstanding. On February 14, 2011, we issued \$210.0 million in aggregate principal amount of our 8.25% Notes due 2018.

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

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 U.S. Gulf of Mexico shelf focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, as it offers a balanced and

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expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations. As of December 31, 2010, we had estimated proved reserves of 27.4 million barrels of oil equivalent, or Mmboe, of which 63% were oil and 93% were proved developed. Of these proved developed reserves, 63% were oil reserves.

Recent Developments

The ASOP Acquisition and Notes Offering. On February 14, 2011, we acquired an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests surrounding the Mississippi River delta and a related gathering system (the ASOP Properties) from Anglo-Suisse Offshore Partners, LLC (ASOP) for \$200.7 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2011 (the ASOP Acquisition). As of December 31, 2010, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves. Of these proved developed reserves, 88% were oil reserves. The ASOP Properties:

include 59 producing wells in three complexes;

had average daily production of approximately 3,344 Boe per day for the three months ended December 31, 2010;

include 48,106 gross and 37,402 net acres; and

include related gathering lines.

The ASOP Acquisition was financed with the proceeds from the sale of \$210 million in aggregate principal amount of 8.25% senior notes due 2018 (the 8.25% Notes) offered to qualified institutional buyers pursuant to Rule 144A promulgated under the Securities Act of 1933, as amended (the Securities Act), and to persons outside the United States pursuant to Regulation S promulgated under the Securities Act. After deducting the initial purchasers' discount and estimated offering expenses, we realized net proceeds of approximately \$202 million. On February 14, 2011, we also entered into an agreement for a new credit facility. See Financial Condition, Liquidity and Capital Resources for more information regarding the 8.25% Notes and the new credit facility.

The ASOP Acquisition provides an opportunity to significantly increase our reserves, production volumes and drilling portfolio, while maintaining our focus on oil-weighted assets in our core area of expertise in the Gulf of Mexico shelf. The ASOP Acquisition also provides us with access to infrastructure and extensive acreage, with significant exploitation and development potential. We intend to pursue exploitation of the ASOP Properties, including recompletions, well reactivations and development drilling, while we analyze the potential for higher-impact exploration prospects. We operate properties containing approximately 60% of the proved reserves attributable to the ASOP Properties. We have begun to implement a three-year commodity price hedging program weighted towards oil in conjunction with the ASOP Acquisition to manage commodity price risks associated with future oil production.

Overview and Outlook

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. We emerged from our Chapter 11 reorganization with an improved capital structure and enhanced financial flexibility. In 2010, we continued to improve our financial strength by repaying all of our high yield PIK Notes (defined below) and entering into the Amended Prior Credit Facility (defined below). See Chapter 11 Reorganization Emergence from Chapter 11 Reorganization.

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

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(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. During 2010 we also continued to focus on (1) achieving meaningful cost reductions in G&A expenses and LOE; (2) converting non-producing reserves to cash flow; and (3) developing a core competency in plugging, abandonment and decommissioning operations. We allocate capital in a rigorous and disciplined manner intended to achieve an overall lower risk capital expenditure profile that focuses on maximizing rate of return and requires projects to compete on that basis.

Our development efforts during 2010 focused on our oil-rich East Bay field where average daily production increased 18% for the year ended December 31, 2010, as compared to the year ended December 31, 2009. As a result, our 2010 average oil production levels exceeded our 2009 levels. Prior to 2010, we established an initial low-risk capital budget oriented towards stabilizing production at the levels experienced in the quarter ended December 31, 2009 and have since continued to develop additional production enhancing opportunities, some of which were approved in excess of our initial capital budget. As of the date of this Annual Report, our fiscal year 2011 capital budget is \$110 to \$125 million (excluding the cost of acquiring the ASOP properties), \$80 million of which is allocated to development of our existing Gulf of Mexico shelf asset base primarily in the East Bay and South Timbalier field areas, \$20 million of which is allocated to exploration projects and an additional \$10 million to \$25 million of which is allocated to development projects within the recently acquired ASOP Properties. We also plan to spend approximately \$17 million in 2011 on plugging, abandonment and other decommissioning activities. Our key areas of operations and our plans for future exploration and development activities do not include any deepwater areas.

We continually review and monitor opportunities to acquire producing properties, leasehold acreage and drilling prospects so that we can act quickly as acquisition opportunities become available. We intend to focus our acquisition strategy on Gulf of Mexico shelf assets that are characterized by production-weighted reserves, seismic coverage and operated positions. We intend to use acquisitions of this type as a key method to replace and grow reserves and production, because we believe this strategy increases production and cash flow visibility while reducing dry hole and exploration risk. We believe our expertise in the Gulf of Mexico shelf and in plugging and abandonment operations allows us to effectively evaluate acquisitions and to operate any properties we eventually acquire.

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 fund any exploration and development expenditures with internally generated cash flows.

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 remain competitive with our offshore Gulf of Mexico industry peers.

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 adversely affect our financial position, our results of operations, our cash flows, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. See **Risk Factors** for a more detailed discussion of these risks.

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.

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Basis of Presentation

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 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 of Reorganization). On September 21, 2009 (the Exit Date), we emerged from Chapter 11 reorganization pursuant to the Plan of Reorganization. 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 of Reorganization 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. For more information on our reorganization, see Chapter 11 Reorganization.

As a result of our reorganization under Chapter 11 and the application of fresh-start accounting in accordance with ASC 852, our financial statements for periods prior to September 30, 2009 are not comparable to our financial statements for periods on or after September 30, 2009. The presentation of combined financial information for the year ended December 31, 2009 is not in accordance with accounting principles generally accepted in the United States (GAAP). However, 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. Therefore, we believe that for purposes of discussion and analysis, those combined financial results are useful for management and investors when analyzing our operational performance and by helping to facilitate a year-to-year discussion. In the following discussion, references to combined results for the year ended December 31, 2009 combine the period 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).

Our depreciation, depletion and amortization (DD&A) was affected 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, estimated reorganization values allocated to our longer-lived oil properties were higher on a per Boe basis than values allocated to our shorter-lived natural gas properties. As a result, our overall DD&A rate per Boe declined for the 2010 period.

Our reported asset retirement obligations (i.e., relating to decommissioning) 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 affected by the credit-adjusted risk-free discount rate applied to our estimated future costs to plug, abandon and perform other decommissioning activities on our oil and natural gas properties. As a result of our reorganization, the credit adjusted risk-free rate we used as 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.

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

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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.

Chapter 11 Reorganization

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 Minerals Management Service (the MMS) (now the BOEMRE) 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 \$150.0 million to \$45.0 million, resulting in a borrowing base deficiency of \$38.0 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 of Reorganization, including entering into a senior secured credit facility consisting of a \$125.0 million revolving credit facility with an initial borrowing base of \$45.0 million (the Prior Revolver) and a \$25.0 million one-year amortizing term loan facility (together with the Prior Revolver, the Prior Credit Facility). On the Exit Date, we drew \$25 million under the Prior 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 net proceeds after this discount were \$55.0 million. The proceeds from the Prior Credit Facility and the PIK Notes were used to repay amounts outstanding of \$83.0 million under the Pre-Reorganization Credit Agreement and to provide working capital for the Company.

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During 2010, a key focus of management was to reduce our cost of capital. In June 2010, we reached an agreement to amend our Prior Credit Facility (the Amended Prior Credit Facility), which enabled us to redeem our PIK Notes. On June 28, 2010, we paid a total of \$70.9 million of principal and accrued interest in connection with the redemption of the PIK Notes. We used cash on hand and a portion of the proceeds of a new \$25.0 million term loan under the Amended Prior Credit Facility to fund the redemption. The Amended Prior Credit Facility established a \$70.0 million borrowing base consisting of the new \$25.0 million term loan and a revolving credit facility with a three-year term that could be used for revolving credit loans and letters of credit up to an initial maximum principal amount of \$45.0 million.

On the Exit Date, we also 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 \$454.5 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 of Reorganization, 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.

Shortly following our emergence from Chapter 11 reorganization, we provided the MMS, now known as the BOEMRE, 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. During April 2010, we regained supplemental waiver status, and we are no longer required to post these surety bonds.

On the Exit Date, the MMS Order was rescinded. 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.

We emerged from our Chapter 11 reorganization with a five-member board of directors whose members were appointed by operation of the Plan of Reorganization 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 Part III of this Annual Report for more information on our board of directors and chief executive officer.

Our Chapter 11 reorganization and related matters are also addressed in Note 4, Reorganization and Fresh-Start Accounting to our consolidated financial statements contained in Part II, Item 8, Financial Statements and Supplementary Data.

Table of Contents**Results of Operations**

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

	Successor Company Year Ended December 31, 2010	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
Net production (per day):					
Oil (Bbls)	6,401	6,091	5,127	5,370	5,608
Natural gas (Mcf)	42,488	45,726	61,029	57,172	45,070
Total (Boe)	13,482	13,712	15,299	14,899	13,120
Average sales prices:					
Oil (per Bbl)	\$ 72.80	\$ 68.03	\$ 49.88	\$ 55.07	\$ 97.42
Natural gas (per Mcf)	4.49	4.42	3.89	3.99	9.46
Total (per Boe)	\$ 48.72	\$ 44.95	\$ 32.22	\$ 35.18	\$ 74.15
Oil & natural gas revenues (in thousands):					
Oil	\$ 170,079	\$ 38,121	\$ 69,812	\$ 107,933	\$ 199,948
Natural gas	69,691	18,587	64,771	83,358	156,074
Total	\$ 239,770	\$ 56,708	\$ 134,583	\$ 191,291	\$ 356,022
Impact of derivatives settled during the period (1):					
Oil (per Bbl)	\$ (3.62)	\$ (1.73)	\$ 1.82	\$ 0.80	\$ (7.85)
Natural gas (per Mcf)	\$ 0.01	\$	\$ 0.01	\$ 0.01	\$ 0.02
Average costs (per Boe):					
LOE	\$ 10.64	\$ 10.63	\$ 11.09	\$ 10.98	\$ 14.98
Taxes, other than on earnings	\$ 2.06	\$ 1.65	\$ 1.43	\$ 1.48	\$ 2.34
G&A expenses	\$ 3.67	\$ 3.60	\$ 4.67	\$ 4.42	\$ 7.77
Increase (decrease) in oil and natural gas revenue due to:					
Change in prices of oil	\$ 34,751			\$ (87,203)	
Change in production volumes of oil	27,395			(4,812)	
Total increase (decrease) in oil sales	62,146			(92,015)	