EPL OIL & GAS, INC.
Form 10-K
March 07, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2012

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

EPL Oil & Gas, Inc.

(Exact name of registrant as specified in its charter)

Delaware	72-1409562
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

201 St. Charles Avenue, Suite 3400

New Orleans, Louisiana 70170
(Address of principal executive offices) (Zip Code)

504-569-1875

Registrant's telephone number, including area code:

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 x 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 ¨ Nox

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. Yesx 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 x No ¨

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

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

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

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

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. Yesx No ¨

The aggregate market value of the common stock held by non-affiliates of the registrant at June 30, 2012 (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 $484,063,819. As of February 28, 2013, there were 39,218,719 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 EPL Oil & Gas, Inc. expected to be held on April 30, 2013 are incorporated by reference into Part III of this Annual Report on Form 10-K.

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

PART I

Item 1. Business

Overview

EPL Oil & Gas, Inc. (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. Effective September 1, 2012, we changed our legal corporate name from "Energy Partners, Ltd." to "EPL Oil & Gas, Inc." through a short-form merger pursuant to Section 253 of the General Corporation Law of the State of Delaware. 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, because the region 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 to identify acquisition opportunities that leverage our technical and operational strengths. As of December 31, 2012, we had estimated proved reserves of 77.4 million barrels of oil equivalent, or Mmboe, of which 61% were oil and 75% were proved developed. Of these proved developed reserves, 65% 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.

2012 Acquisitions

On October 31, 2012, we acquired from Hilcorp Energy GOM Holdings, LLC ("Hilcorp") 100% of the membership interests of Hilcorp Energy GOM, LLC ("Hilcorp Acquisition"), which owned certain shallow water Gulf of Mexico shelf oil and natural gas interests (the "Hilcorp Properties"), for $550 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. As of December 31, 2012, the Hilcorp Properties had estimated proved reserves of approximately 37.2 Mmboe, of which 49% were oil and 58% were proved developed reserves. The Hilcorp Properties include three core producing complexes, 139 total producing wells, 215,033 gross (149,386 net) acres and related gathering lines.

The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of $300 million in aggregate principal amount of 8.25% senior notes due 2018 (the "2012 Senior Notes") and borrowings under our expanded senior credit facility. The 2012 Senior Notes were offered in a private placement only to qualified institutional buyers under

Rule 144A promulgated under the Securities Act of 1933, as amended (the "Securities Act"), or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. After deducting the initial purchasers' discount, we realized net proceeds of $289.5 million. Also on October 31, 2012, we obtained an increase in our senior secured credit facility from $250 million to $750 million under which we borrowed $205 million to fund a portion of the purchase price and related expenses of the Hilcorp Acquisition.

In the June 20, 2012, Central Gulf of Mexico Lease Sale 216/222, we were the high bidder on six leases covering a total of 27,148 acres on a gross and net basis. This acreage is located in the shallow Gulf of Mexico shelf within our core area of operations. Our share of the high bids totaled approximately $7 million.

On May 15, 2012, we acquired from W&T Offshore, Inc. ("W&T") an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests in our South Timbalier 41 field ("ST41 Interests") located in the Gulf of Mexico for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012

(the "ST41 Acquisition"). Prior to the ST41 Acquisition, we owned a 60% working interest in the properties, and W&T owned a 40% working interest. As a result of the ST41 Acquisition, we have become the sole working interest owner of the South Timbalier 41 field. The ST41 Interests had estimated proved reserves as of the acquisition date of approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. We funded the ST41 Acquisition with cash on hand.

2011 Acquisitions

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"). On November 17, 2011, we acquired certain interests in producing oil and natural gas assets in the shallow-water central Gulf of Mexico shelf (the "Main Pass Interests") from Stone Energy Offshore, L.L.C. for $38.6 million in cash, subject to customary adjustments to reflect an economic effective date of November 1, 2011 (the "Main Pass Acquisition"). The Main Pass Interests consist of additional interests in the Main Pass 296/311 complex that was included in the assets we purchased from ASOP, along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease. As of their respective acquisition dates, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves, and the Main Pass Interests had estimated proved reserves of approximately 1.3 Mmboe, of which 96% were oil and 100% were proved developed producing reserves.

We financed the ASOP Acquisition with the proceeds from the sale of $210 million in aggregate principal amount of 8.25% senior notes due 2018 (the "2011 Senior Notes"). After deducting the initial purchasers' discount and estimated offering expenses, we realized net proceeds of approximately $202 million from the sale of the 2011 Senior Notes. We funded the Main Pass Acquisition with cash on hand.

Recent Events

On March 5, 2013 we executed a purchase and sale agreement to sell certain shallow water Gulf of Mexico shelf oil and natural gas interests located within the Bay Marchand field area to the property operator for $51.5 million in cash and the buyer's assumption of liabilities currently recorded on our balance sheet of $10.8 million resulting in total consideration of $62.3 million, subject to customary adjustments to reflect a January 1, 2013 economic effective date. We do not operate these assets, which are currently producing approximately 400 Boe per day, about 97% of which are oil. Estimated proved reserves as of the January 1, 2013 economic effective date totaled approximately 1.6 million Boe, 90% of which are oil. We expect to close the transaction by April 1, 2013 and record a gain on the sale.

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 net proved reserves as of December 31, 2012 were 75% proved developed, which provides significant production visibility. Moreover, we have an inventory of lower risk exploitation projects with 257 behind pipe opportunities and 35 identified proved undeveloped reserves locations. 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. Our net proved reserves at December 31, 2012 were approximately 61% oil, and our net average daily production for the year ended December 31, 2012 was 78% 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 natural gas decline curve, resulting in longer

term production from current reserves.

Operational Control. We operate properties that contain approximately 86% 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 and development plans in response to changes in commodity prices.

Geographically Focused Properties in the Gulf of Mexico. We are focused on operating properties located in the Gulf of Mexico shelf, which gives us the opportunity to minimize logistical and administrative costs and maximize the productivity of our field personnel. Our concentration of long-lived, oil rich legacy fields provides attractive future consolidation opportunities as evidenced by the Hilcorp Acquisition. 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. In 2012 we acquired additional 2-D and 3-D seismic data sets in our current offshore operating areas and onshore Louisiana where the geology is characterized by similar productive horizons and structural features. In addition to the extensive seismic library we have of our legacy properties, we have licensed high quality multi-client 3-D data sets for recently acquired fields. We now have approximately 18,900 square miles of 3-D seismic data in the Gulf of Mexico and onshore Louisiana. This seismic data assists us in identifying attractive development and exploration drilling opportunities that adhere to our capital-efficient development strategies. We continue to high-grade these data sets by employing state-of-the-art reprocessing techniques for the data covering our core fields and on a regional basis around those fields. These technological upgrades are creating better images of prospective horizons and aiding in the evaluation of drilling opportunities.

Delevering and Conservative Fiscal Policy. We budget our capital spending on exploration and development with the goal of remaining within cash flow from operations, allowing free cash flow from our asset base to reduce debt. We have a long-term leverage target of $6 to $7 per Boe of proved reserves. We have hedged approximately 57% of our forecasted oil production in 2013 and have placed substantial oil hedges for 2014.

Experienced Management and Significant Technical Expertise. We have an experienced and technically-adept management team, averaging more than 25 years of industry experience among our top nine 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.

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 lower-risk exploitation opportunities, as well as exploration prospects with multiple objectives and follow-up opportunities. In 2012, we completed 18 workovers and 15 drill wells, with an 85% success rate, spending approximately $223 million on development and exploration activities, including seismic purchases of $11 million. We also spent approximately $7 million on undeveloped leases in 2012. Our fiscal year 2013 capital budget is $300 million, which is allocated to development activities and exploration projects within existing core field areas. Additionally, we plan to spend approximately $30 million in 2013 on plugging, abandonment and other decommissioning activities. We will continue to focus on lower-risk development projects, as well as a small number of high quality, high potential exploration prospects. We believe the properties we acquired in 2011 and 2012 enhance our exploitation strategy to increase production from legacy fields and provide us with substantial incremental exploration opportunities within those fields.

Build upon Regional Geologic Expertise. We are dedicating significant resources to add to our knowledge of the geology underlying our core areas. We have recently acquired additional 2-D and 3-D seismic data sets in our current offshore operating areas and onshore Louisiana, where the geology is characterized by similar productive horizons and structural features. Our geological and geophysical teams are analyzing well data, paleontological data and seismic data to identify exploration targets at intermediate and deep depths as well as associated acquisition opportunities.

Target Acquisition Opportunities to Grow Reserves and Leverage Operational Strengths. We continue to 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. Our acquisition strategy is focused on operated Gulf of Mexico shelf and Gulf Coast assets that are characterized by production-weighted reserves, seismic coverage and operated positions that would allow us to maintain a conservative capital structure. We intend to use acquisitions of this type as a key method to 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 and Gulf Coast region allows us to effectively evaluate acquisitions and to operate the properties we eventually acquire.

Maintain Financial Discipline. We strive to maintain a conservative financial position, sufficient liquidity and a strong balance sheet. We establish our capital spending plans with the goal of funding those costs with cash flows from operations, allowing any remaining free cash flow to be used for debt reduction. We currently have access to our senior credit facility (the "Senior Credit Facility") into which we entered on February 14, 2011 and that was amended and restated on October 31, 2012 in connection with the Hilcorp Acquisition to increase the aggregate commitment under the facility from $250 million to a maximum of $750 million and to extend the maturity date to October 31, 2016. We currently have a borrowing base of $425 million. As of February 28, 2013, we had $240 million in availability under our Senior Credit Facility. In order to maintain financial flexibility, we plan to fund our 2013 fiscal year exploration and development capital budget with cash flow from operations. Additionally, because we operate many of our properties, we are able to manage the timing of a substantial portion of our capital investments. We may fund future acquisitions with a combination of cash on hand, borrowings under our credit facility and issuances of debt and equity securities under our universal shelf registration statement that became effective under the Securities Act of 1933 in July 2011.

Capitalize on Competency in Plugging and Abandonment. We have established and are executing on a proactive, multi-year plan to plug, abandon and decommission depleted wells and associated infrastructure. Our president and chief executive officer has significant experience in conducting these types of operations and has supplemented our staff to accomplish this objective. In our East Bay field where our abandonment and decommissioning obligations are concentrated, we have completed plugging and abandonment operations on more than 30% of the inactive wellbores. We expect to reduce our lease operating expense over time by removing idle infrastructure and its associated maintenance costs. The three core producing complexes that comprise the Hilcorp Properties are located in the shallow-water Gulf of Mexico shelf region in water depths ranging from 20 feet to 190 feet. These complexes are situated similarly to, and are concentrated near, our previously existing assets. The facilities and structures supporting the Hilcorp Properties have longer useful lives and fewer idle assets than many of our other assets. As a result, we expect that less current spending will be required for abandonment work in those properties than for our previously existing assets.

Where You Can Find More Information

We maintain a website at www.eplweb.com that contains information about us, which information is available free of charge, 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 electronically filing such reports with, or furnishing them to the Securities and Exchange Commission (the "SEC"). In addition, our website contains our Corporate Governance Guidelines and the charters for our Audit, Compensation and Nominating and Governance Committees. Copies of this information are also available by writing to our Corporate Secretary at 201 St. Charles Avenue, Suite 3400, New Orleans, Louisiana 70170. Our website and the information contained in it and connected to it shall not be deemed incorporated by reference into this Annual Report or any other filing that we make with the SEC.

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

Properties

As of December 31, 2012, we had working interests in 37 producing fields located in the Gulf of Mexico shelf region, including the following:

- our East Bay producing field on the southern flank of the Mississippi River delta;
- three producing fields in the South Timbalier area;
- two producing fields in our West Delta complex;
- one producing field in our Ship Shoal 208 complex;
- one producing field in our South Pass 78 complex;
- two producing fields in our Main Pass complex;
- one producing field in our South Marsh Island 239 complex; and

- 26 other producing fields offshore Louisiana.

Our East Bay field comprised approximately 21% of our production during the year ended December 31, 2012 and 17% of our proved reserves at December 31, 2012. 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 209 producing wells located along the coastline and in water depths up to approximately 70 feet. We operate this field and own an average 96% working interest in our acreage position in this area. Our leasehold area covered 30,055 gross acres (28,948 net acres) as of December 31, 2012.

Our South Timbalier area comprised approximately 24% of our production during the year ended December 31, 2012 and 12% of our proved reserves at December 31, 2012. Our key assets in this area include the South Timbalier 26 and 41 fields located approximately 60 to 72 miles south of New Orleans in water depths of approximately 73 feet or less. We operate the South Timbalier 26 and 41 blocks, and we own working interests ranging from 13% to 100% in this area.

Our West Delta complex comprised approximately 25% of our production during the year ended December 31, 2012 and 11% of our proved reserves at December 31, 2012. The West Delta complex, a legacy producing area, is located 62 miles south southeast of New Orleans. It contains 34 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 an average 99% working interest in our acreage position in this area.

Our Main Pass complex comprised approximately 8% of our production during the year ended December 31, 2012 and 7% of our proved reserves at December 31, 2012. The Main Pass complex is located 98 miles southeast of New Orleans. It contains 33 producing wells in average water depths of approximately 250 feet and is comprised of two fields. We own a non-operated 50% working interest in most of our acreage position in this area.

During 2012, we concentrated on exploration and exploitation opportunities in the South Timbalier, West Delta and Main Pass areas and evaluated certain well proposals in these areas using our recently reprocessed 3-D seismic data.

We acquired the Ship Shoal 208 complex, South Pass 78 complex and South Marsh Island 239 complex in the Hilcorp Acquisition on October 31, 2012. Production from these three complexes is included in our results only from the October 31, 2012 closing date of the Hilcorp Acquisition and comprised approximately 7% of our production during the year ended December 31, 2012. For the period from October 31, 2012 to December 31, 2012, production from these areas comprised approximately 27% of our total production.

The Ship Shoal 208 complex comprised 22% of our proved reserves at December 31, 2012. This complex is located 110 miles southwest of New Orleans. It contains 33 producing wells in average water depths of approximately 100 feet in three lease blocks. We operate the Ship Shoal 208 complex and own a working interest of 100% of the acreage position in this area.

Our South Pass 78 complex comprised approximately 9% of our proved reserves at December 31, 2012. This complex is located 86 miles southeast of New Orleans. It contains 26 producing wells in water depths ranging from approximately 140 to 190 feet in four lease blocks. We operate the South Pass 78 complex and own a working interest of 67% of the acreage position in this area.

Our South Marsh Island 239 complex comprised approximately 4% of our proved reserves at December 31, 2012. This complex is located 117 miles southwest of New Orleans. It contains nine producing wells in water depths of approximately 20 feet in four lease blocks. We operate the complex and own a working interest of 92% in the acreage position in this area.

The 26 other producing fields offshore Louisiana comprised approximately 13% of our production during the year ended December 31, 2012 and 17% of our proved reserves at December 31, 2012. These properties are located in water depths ranging from approximately 18 to 300 feet with working interests ranging from 20% to 100%.

As of December 31, 2012, we also owned interests in 15 undeveloped leases and one producing lease in the deepwater Gulf of Mexico. These deepwater Gulf of Mexico properties comprised approximately 2% of our production during the year ended December 31, 2012 and 1% of our proved reserves at December 31, 2012. Our working interests in our leases in this area ranged from 15% to 100%.

Oil and Natural Gas Reserves

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, 2012, 2011 and 2010. Our estimates of proved reserves are based on reserve reports prepared as of December 31, 2012 by Netherland, Sewell & Associates, Inc. (“NSAI”) and W.D. Von Gonten & Co. (“WDVG”), 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 15 “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.

We follow the oil and gas reserves estimation and disclosure requirements of Accounting Standards Codification (“ASC”) Topic 932, “Extractive Activities—Oil and Gas” (“ASC 932”), which requires, among other things, that prices used to

estimate reserves for SEC disclosure purposes reflect an unweighted, arithmetic average price based upon the closing price on the first day of each of the twelve months during the fiscal year, rather than the year-end price. See Note 15 "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 reporting related to oil and natural gas reserves under ASC 932.

	As of December 31,		
	2012	2011	2010
	(dollars in thousands)		
Total estimated net proved reserves:			
Oil (Mbbls)	47,442	27,301	17,223
Natural gas (Mmcf)	179,939	58,785	61,251
Total (Mboe)	77,432	37,099	27,431
Net proved developed reserves (1):			
Oil (Mbbls)	37,908	24,791	15,974
Natural gas (Mmcf)	120,687	52,739	56,410
Total (Mboe)	58,022	33,581	25,376
Net proved undeveloped reserves:			
Oil (Mbbls)	9,534	2,510	1,249
Natural gas (Mmcf)	59,252	6,046	4,841
Total (Mboe)	19,409	3,518	2,055
Estimated future net revenues before income taxes (2)	$ 2,641,407	$ 1,555,059	$ 565,922
Present value of estimated future net revenues before income taxes (PV-10) (2)(3)(5)	$ 1,979,274	$ 1,100,701	$ 413,066
Standardized measure of discounted future net cash flows (4)(5)	$ 1,574,282	$ 876,169	$ 359,458

(1) Net proved developed non-producing reserves as of December 31, 2012 (15,154 Mbbls and 80,883 Mmcf) were 28,634 Mboe, or 37% of our total proved reserves.

(2) Calculated using oil prices of $105.13, $108.48 and $77.85 per barrel, respectively, and natural gas prices of $2.92, $4.16 and $4.54 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.

(3) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, determined in the manner described in footnote (2), discounted at a rate of 10% per year on a pre-tax basis.

(4) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10% per year, as calculated in accordance with SEC guidelines and pricing.

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

As of December 31, 2012, our proved undeveloped reserves (“PUDs”) include 15.4 Mmboe attributable to the Hilcorp Properties. We expect our PUDs as of December 31, 2012 of 19.4 Mmboe to begin converting from proved undeveloped to proved developed as the planned development projects begin in 2013. We project future development costs relating to the development of the PUDs remaining at December 31, 2012 to be approximately $169.4 million in 2013, $35.2 million in 2014, $0.9 million in 2015 and $26.9 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, 2012, our estimates of proved reserves are based on reserve reports prepared by the independent petroleum engineering firms NSAI and WDVG, both nationally recognized engineering firms. At December 31, 2012, estimates of 52% of our total estimated net proved reserves were prepared by NSAI and 48% were prepared by WDVG. WDVG's reserve report was prepared with respect to the Hilcorp Properties. Letters from NSAI and WDVG are filed as exhibits to this Annual Report on Form 10-K.

NSAI provides a complete range of geological, geophysical, petrophysical and engineering services and have the technical experience and ability to perform these services in any of the onshore and offshore oil and gas producing areas of the world. NSAI has a technical staff of over 70 professionals who are knowledgeable with regard to recognized industry reserves and resource definitions, specifically those set forth by the SEC.

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.

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.

The table below sets forth production information for each field that contains 15% or more of our total proved reserves as of December 31, 2012. The Ship Shoal 208 field was acquired in the Hilcorp Acquisition and the table below reflects production for this field only for the period from November 1, 2012 through December 31, 2012.

	Year Ended December 31,		
	2012	2011	2010
East Bay:			
Oil (Mbbls)	1,035	1,062	1,031
Natural gas (Mmcf)	47	76	78
Total (Mboe)	1,043	1,075	1,044
Ship Shoal 208:			
Oil (Mbbls)	109	-	-
Natural gas (Mmcf)	199	-	-
Total (Mboe)	142	-	-

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.

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Acquisitions—Proved (1)	$ 706,322	$ 261,812	$ -
Acquisitions—Unproved	7,496	14	623
Exploration	43,338	17,129	31,463
Development (2)	180,938	83,577	25,643
Costs incurred	$ 938,094	$ 362,532	$ 57,729

(1) Includes asset retirement obligations associated with acquisitions totaling $132.1 million and $26.4 million during the years ended December 31, 2012 and 2011, respectively.

(2) Includes asset retirement obligations incurred associated with finding, acquiring and developing our proved oil and natural gas reserves of $1.2 million, $0.2 million and $0.1 million during the years ended December 31, 2012, 2011 and 2010, respectively.

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, 2012.

	Total Productive Wells	
	Gross	Net
Oil	378	268
Natural gas	119	74
Total	497	342

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. Twelve gross oil wells and four gross natural gas wells have dual completions.

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

Acreage

The following table sets forth information relating to acreage held by us as of December 31, 2012. Developed acreage is assigned to producing wells.

	Gross Acreage	Net Acreage
Developed:		
Gulf of Mexico Shelf	337,001	242,176
Deepwater Gulf of Mexico	5,760	1,599
Other	605	197
Total	343,366	243,972
Undeveloped:		
Gulf of Mexico Shelf	104,526	102,245
Deepwater Gulf of Mexico	80,640	21,663
Total	185,166	123,908

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. As of December 31, 2012, the net book value of the leases expiring in 2013 and 2014 was $0.1 million and $0.3 million, respectively. Leases covering 52% of our undeveloped net acreage expire in 2013, 11% expire in 2014, 5% expire in 2015, 6% expire in 2016, 23% expire in 2017 and 3% expire thereafter. We currently plan to develop opportunities for leases covering 4% of the net

acreage expiring in 2013.

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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 following table shows our drilling activity where “gross” refers to the total wells in which we have a working interest and “net” refers to gross wells multiplied by our working interest in these wells.

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	11.0	9.5	4.0	3.6	1.0	1.0
Non-productive	1.0	1.0	1.0	1.0	-	-
Total	12.0	10.5	5.0	4.6	1.0	1.0
Exploratory Wells						
Productive	1.0	0.8	4.0	1.3	7.0	4.9
Non-productive	2.0	0.7	1.0	0.5	2.0	1.5
Total	3.0	1.5	5.0	1.8	9.0	6.4
Recompletion Operations						
Productive	16.0	14.2	23.0	19.1	14.0	11.2
Non-productive	2.0	2.0	4.0	3.3	5.0	5.0
Total	18.0	16.2	27.0	22.4	19.0	16.2

We are currently in the process of drilling three gross (2.8 net) development wells in our West Delta area. We drilled two gross (0.8 net) exploration wells late in 2011 which reached their target depths in January 2012 and were determined to be unsuccessful.

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

Regulatory Matters

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our

operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Regulation of Natural Gas Gathering. Section 1(b) of the Natural Gas Act of 1938, as amended (the "NGA"), exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("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 Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("BSEE"), pursuant to The Outer Continental Shelf Lands Act ("OCSLA"), because they traverse the OCS pursuant to federal easements. As discussed herein, the BOEM and BSEE were created on October 1, 2011 to replace the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") as part of a reorganization aimed at separating the resource management and enforcement functions of the former Minerals Management Service. OSCLA authorizes regulations governing the preparation of spill contingency plans and establishing air quality standards for certain pollutants, including particulate matter, volatile organic compounds, sulfur dioxide, carbon monoxide and nitrogen oxides. Specific design and operational standards may apply to outer continental shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations related to the environment issued pursuant to OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and canceling leases. Such enforcement liabilities can result from either governmental prosecution or private action.

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

Though our natural gas gathering facilities are not subject to regulation by the FERC 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."

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, some of our operations may be required to annually report to the FERC, 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 Safety, Availability, Terms and Cost of Pipeline Transportation. Our onshore and offshore pipelines are subject to safety regulation by the Pipeline and Hazardous Materials Administration of the U.S. Department of Transportation (the "PHMSA"), BSEE and/or state agencies, depending on the location and services provided by each pipeline. 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 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 four pipelines subject to regulation by the FERC: (1) 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; (2) an approximately eight-mile pipeline that runs between South Marsh Island Block 239 through Mound Point B and South Marsh Island Block 205 to Lighthouse Point A, South Marsh Island Block 207 on the Gulf of Mexico OCS to Vermillion Parish, Louisiana; (3) an approximately nine-mile pipeline that runs between South Pass Block 78 and South Pass Block 55 on the Gulf of Mexico OCS; and (4) an approximately ten-mile pipeline that runs between South Pass Block 55 and West Delta Block 83 on the Gulf of Mexico OCS to Plaquemines Parish, Louisiana. The ICA requires that we maintain tariffs on file with the FERC for these pipelines. The tariffs set forth the rates, which were established as negotiated rates that have not been protested, as well as the rules and regulations governing these services. 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 a challenge is made to a newly filed increased rate and FERC ultimately finds that the proposed rate is unlawful following an investigation, FERC is permitted to change that rate prospectively from the date of its decision, and may order refunds representing the difference between the challenged increased rate and the previous lawful rate. If a complaint is filed against an existing rate, FERC may award reparations for the two year period prior to the date of the complaint.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005. The Energy Policy Act of 2005 ("EPAct 2005") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. With respect to regulation of natural gas transportation, EPAct 2005 amended the NGA by increasing the criminal penalties available for violations of each Act. EPAct 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. EPAct 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. FERC's regulations make 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. The regulations do not directly apply to activities that relate only to non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities (including those which engage in non-jurisdictional sales or gathering) to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements and daily scheduled flows.

FERC Market Transparency Rules. FERC's regulations require 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) to report, on May 1 of each year, 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.

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 and establish requirements for 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 and natural resource damages resulting from our operations.

Failure to comply with these laws and regulations could 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. We believe that we are in substantial compliance with currently applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. For example, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2012, and we are not aware of any environmental issues or claims that will require material capital expenditures during 2013. Nevertheless, accidental spills or releases may occur in the course of our operations, and we cannot give any assurances that we will not incur substantial costs and liabilities, as a result of such spills or releases, which would not be covered by insurance, including those relating to claims for damage to property and persons. Moreover, we cannot give any assurance that the passage of more stringent or additional laws or regulations in the future will not materially adversely affect our business, results of operations and financial condition.

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, including the OCS waters where we have substantial operations. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. OPA also requires 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, including penalties and natural resource damages.

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 current 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 strict 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. 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.

While the term "hazardous substance" under CERCLA does not include petroleum, natural gas, NGLs, liquefied natural gas, or synthetic gas usable for fuel, we may generate wastes that fall within CERCLA's definition of a "hazardous substance" in the course of our ordinary operations. We also 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, we may still be responsible if "hazardous

substances" were disposed or released on, under or from these properties or on, under or from other locations where these wastes have been taken for disposal. CERCLA authorizes the federal 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 responsible parties the costs they incur. 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 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 of 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. 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, federal 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 BSEE also issues Notices to Lessees and Operators ("NTLs") that provide guidance on the implementation of and compliance with Outer Continental Shelf Lands Act ("OCSLA") regulations. Many of these NTLs, with which we must comply, relate to the prevention of harm to marine species.

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, are increasingly the subject of citizen group intervention and challenge, 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 BSEE 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. EPA continues to consider and promulgate new or revised regulations under the Clean Air Act, such as the recently revised New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants applicable to the oil and gas industry sector, that generally impose more stringent regulations upon aspects of our business. We could be required to incur costs in the future to make operational changes or to purchase additional air pollution control equipment in order to comply with these changing regulations, 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 currently applicable air pollution control laws and requirements.

Climate Change. Scientific studies have suggested that emissions of certain “greenhouse gases,” including carbon dioxide and methane, may be contributing to warming of the Earth’s atmosphere. International negotiations to address climate change have occurred in response to such studies. In 2009, the United States submitted a non-binding greenhouse gas emission reduction target of 17 percent compared to 2005 levels pursuant to the Copenhagen Accord and negotiations continue under the United Nations Framework Convention on Climate Change. In the United States, Congress has considered legislation to reduce emissions of greenhouse gases; however, no such legislation has been passed. It is uncertain at this time whether, and in what form, federal climate change legislation will be adopted.

In the absence of over-arching federal climate change legislation, many states are regulating greenhouse gas emissions. Certain states, either individually or through multi-state regional initiatives, have passed laws, adopted regulations or undertaken regulatory activity to reduce emissions of greenhouse gases.

The EPA is also regulating greenhouse gas emissions from both mobile and certain large stationary sources under its existing authority pursuant to the Clean Air Act. In 2009, the EPA published its finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. Thereafter, the EPA promulgated regulations requiring that major sources in the United States collect and report information regarding greenhouse gas emissions. 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, data collection began on January 1, 2011 and the first annual reports were due on March 31, 2012. In January 2011, new EPA permitting requirements became effective for greenhouse gas emissions from new and modified large stationary sources.

Courts are addressing climate change issues as well. Many of the EPA’s greenhouse gas rules are undergoing legal challenges and numerous other challenges are being filed by groups seeking additional regulation of a variety of additional sources of greenhouse gas emissions. On June 20, 2011, the U.S. Supreme Court issued a decision that bars state and private parties from bringing federal common law nuisance actions against certain energy companies based on their alleged contribution to climate change. The Supreme Court’s decision did not, however, address state law claims. This decision is expected to affect pending and future federal climate change cases. Although we are not currently a party to such litigation, we are monitoring these developments.

It is not possible at this time to predict what new regulations may be promulgated to address greenhouse gas emissions or how the promulgation of any such 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.

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 or may become more difficult or expensive to secure if such storms occur with increasing frequency. 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. Offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, and facility removals, were formerly regulated by BOEMRE. On October 1, 2011, the U.S. Department of the Interior completed its reorganization of the BOEMRE (formerly the Minerals Management Service) by the creation of three independent agencies, each with its own offshore oil and gas responsibilities: the BOEM, with responsibility for leasing and environmental studies; the BSEE, with responsibility for field operations, including inspections, regulatory compliance, and oil spill response; and a third agency for management of revenues. The BOEMRE now ceases to exist. At this time, we believe that our operations are in material compliance with applicable regulations and orders. We cannot predict, however, the impact that the BOEMRE reorganization, or future regulations or enforcement actions taken by the new agencies, may have on our operations.

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

We are subject to an active NTL, effective October 15, 2010, on the decommissioning of wells and platforms. 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, approval was granted 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 did not include the properties we acquired from ASOP. In December 2011, we submitted to the BSEE a plan related to the ASOP Properties for plugging, abandonment and decommissioning activities through 2014. For the Hilcorp Properties, we are currently operating under the approved three-year plan submitted by Hilcorp Energy GOM, LLC in February 2012.

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 OCS. The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. Both the BOEM and the BSEE are concerned about 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 former BOEMRE issued still active 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 BOEM or BSEE in the future and these new requirements could increase our operating costs. The BOEM, BSEE 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 could result in substantial penalties, including lease termination in the case of federal leases. Under limited circumstances, the BSEE could require us to suspend or terminate our operations on a federal lease or we could have difficulty entering into new leases in the future. 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 our oil and natural gas production. We sell our natural gas to marketing companies pursuant to a variety of contractual arrangements, generally under contracts with terms no longer than six to twelve months. Pricing on those contracts is based largely on published regional index pricing. We sell our oil under contracts with month-to-month terms to a variety of purchasers. The pricing for oil is based upon the posted prices set by major purchasers in the production area, reporting publications, or upon New York Mercantile Exchange ("NYMEX") pricing. Oil pricing is adjusted for quality and transportation differentials. Oil and natural gas purchasers are selected on the basis of price, credit quality and service reliability.

Our oil, condensate and natural gas production is sold to a variety of purchasers, historically at market-based prices. We believe that the prices for liquids and natural gas are comparable to market prices in the areas where we have production. Of our total oil and natural gas revenues in 2012, ConocoPhillips accounted for approximately 45%, Chevron USA, Inc. accounted for approximately 31% and Shell Trading (US) Company 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, 2012, we had 173 full-time employees, including 31 geoscientists, engineers and technicians and 100 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 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.

Seasonality

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

Cautionary Statement Concerning Forward Looking Statements

This Annual Report contains 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 generally 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 simi

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 Senior Credit Facility;
- 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 BOEM, the BSEE and the PHMSA;
- the impact of political and regulatory developments;
- risks and liabilities associated with acquired properties or businesses;
- our ability to make and integrate acquisitions;
- our substantial level of indebtedness;

- our ability to incur additional indebtedness;
- 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 credit facility, we intend to finance our development and exploration capital expenditures with 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 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 credit facility and the indentures governing our senior notes. If we are unable to make scheduled payments on our credit facility, or if our financing requirements are not met by our 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 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 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 Senior Credit Facility is $425 million. As of February 28, 2013, we had $185.0 million outstanding under our Senior 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, 2013. 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 credit facility.

In the future, we may not be able to access adequate funding under our 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 credit facility may be reduced. As a result, we may be unable to obtain adequate funding under our 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 credit facility exceed the

re-determined borrowing base, we will be required to repay half of such difference within forty-five (45) days and the other half of such difference within ninety (90) days. We may not have the financial resources in the future to make any mandatory principal prepayments required under our Senior Credit Facility, which would result in an event of default under the Senior 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 2011 Senior Notes and the 2012 Senior Notes (collectively, the "8.25% Notes"), on a consolidated basis at December 31, 2012, had outstanding $705.0 million of senior indebtedness, including $195.0 million of secured debt under our Senior Credit Facility. 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;

- 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 indentures governing the 8.25% Notes (the "Indentures") and our 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 our substantial level of indebtedness we may still be able to incur substantially more indebtedness, 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, 2012, we had total debt outstanding of $705.0 million consisting of $210.0 million of the 2011 Senior Notes, $300.0 million of the 2012 Senior Notes and $195.0 million of outstanding borrowings under our Senior Credit Facility, and we had $230.0 million in availability under our Senior Credit Facility due to its borrowing base limitations. Although the terms of the 2011 Senior Notes, the 2012 Senior Notes and our current 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 Senior Credit Facility and the Indentures 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 Senior Credit Facility and the Indentures contain covenants that restrict our and our restricted subsidiaries' or, in the case of the Senior 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 Indentures 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;

- 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 other than those related to our business as a domestic exploration and production company;

- issuing capital stock of certain subsidiaries;

- entering into sale/leaseback transactions;

- making acquisitions or investments; and

- designating subsidiaries as unrestricted subsidiaries.

In addition, our Senior Credit Facility restricts us from entering into certain hedging contracts or extending credit. Our 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 credit facility and the indentures 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 credit facility, the Indentures 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 notes and the terms of our other indebtedness outstanding at such time. If the amounts outstanding under our Senior 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 prices have 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 oil prices will not fall again. Domestic natural gas prices have recently experienced ten year lows and may remain at these low levels relative to historical prices for an extended period of time. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include:

- changes in the global supply, demand and inventories of oil;
- domestic natural gas supply, demand and inventories;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of foreign imports of oil;
- the price and availability of liquefied natural gas imports;

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

- 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 affecting energy consumption; and

- the price and availability of alternative fuels.

Oil 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 oil 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.

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, impacts of adverse weather conditions 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.

At December 31, 2012, the Ship Shoal 208 and East Bay fields contained approximately 22% and 17%, respectively, of our estimated proved reserves. 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, 2012, our independent petroleum engineers estimate that, on average, 65% 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 oil and natural gas 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, 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, including the inability to adapt technological advancements to a Gulf of Mexico setting, 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, 2012, we operated approximately 86% of our properties, based on proved reserves at December 31, 2012. 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.

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.

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 oil and natural gas price volatility on our cash flow from operations. Currently, we use a combination of crude oil swap and collar arrangements to mitigate the volatility of future 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.

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

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

- the board of directors' ability to issue shares of preferred stock and determine the terms of the preferred stock without approval of common stockholders; and

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

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

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;

- 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, results of operations and cash flows. 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 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.

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 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 may not be 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.

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.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows 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, related PV-10 and standardized measure of discounted future net cash flows as of December 31, 2012, 2011 and 2010, 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.

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 proved reserves as of December 31, 2012 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. As of December 31, 2012, approximately 25% of our total proved reserves were undeveloped, and approximately 37% of our total proved reserves were developed non-producing reserves. There can be no assurance that all of those reserves will ultimately be developed or produced.

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 2013 fiscal year capital budget contemplates the deployment of a significantly larger amount of capital compared to the capital expenditures in 2012, 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 well, 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. 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 excess liabilities coverage with an aggregate limit of $150.0 million applicable to our working interests. Our general liability policy is subject to a $25,000 per incident deductible. We also have an offshore property physical damage and operators extra expense policies that contain an aggregate of $175.7 million of named windstorm limit of which we self-insure approximately 9%. Recoveries from these policies are subject to a $2.5 million deductible that applies to non-named windstorm occurrences and a $20.0 million deductible that applies to named windstorm events except for East Bay central facilities and rental compressor losses, which are subject to a 1.5% deductible of the scheduled values of the items making up a loss, but always subject to a $25,000 minimum. Further, there are sub-limits within the named windstorm annual aggregate limit for re-drill, non-blowout plugging and abandonment and excess removal of wreck. 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 $150.0 million in oil pollution liability coverage as required under the Oil Pollution Act of 1990. 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, to which the $50.0 million limit applies to our working interest. 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 materially adversely 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 materially adversely impact our financial position. For example, we experienced production interruptions in 2005, 2006 and 2007 from Hurricanes Katrina and Rita, in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance.

We regularly reevaluate the purchase of insurance, policy limits and terms. 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 maintain an Oil Spill Response Plan (the "Plan") that defines our response requirements and procedures and remediation plans in the event we have an oil spill. Oil Spill Response Plans will generally be approved by the BSEE bi-annually, except when changes are required, in which case revised plans are required to be submitted for approval at the time changes are made. We believe the Plan specifications are consistent with the requirements set forth by the BSEE.

The Company has contracted with an emergency and spill response management consultant, which would provide management expertise, personnel and equipment, under the supervision of the Company, in the event of an incident requiring a coordinated response. Additionally, the Company is a member of Clean Gulf Associates ("CGA"), a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico and has capabilities to simultaneously respond to multiple spills. CGA is structured to provide an effective method of staging response equipment and providing spill response for its member companies in the Gulf of Mexico. On January 1, 2013, CGA entered into an agreement with Clean Gulf Associates Services, LLC ("CGAS"), an affiliate of T&T Marine Salvage Inc. ("TTMS"). Through this agreement, CGAS will store, maintain, deploy and operate all CGA-owned equipment and provide response personnel. This agreement replaces the expiring Equipment Management, Contractor Services and Bareboat Charter Agreement that CGA had previously entered into with Marine Spill Response Corporation. CGAS maintains CGA's equipment in various warehouse locations (currently including 54 skimmers with various estimated daily recovery capacities, numerous containment and storage systems including thousands of feet of boom and one fire boom system, tanks and storage barges, wildlife cleaning and rehabilitation facilities, and both aerial and vessel dispersant spray systems) at staging points around the Gulf of Mexico in its ready state. In the event of a spill, CGAS mobilizes appropriate equipment to CGA members. In addition, CGA maintains a contract with Airborne Support Inc., which provides aircraft and dispersant capabilities for CGA member companies.

Additional resources are available to the Company on an as-needed basis other than as a member of CGA, such as those of CGAS. CGAS has oil spill response equipment independent of, and in addition to, CGA's equipment. CGAS's equipment currently includes, according to CGAS's website, skimmer, containment boom, pumps and lightering equipment, vacuum units and sorbents. In the event of a spill, CGAS activates contractors as necessary to provide

additional resources or support services requested by its customers.

The response effectiveness, equipment and resources of these companies may change from time-to-time and current information is generally available on the websites of each of these organizations. There can be no assurances that the Company, together with the organizations described above will be able to effectively manage all emergency and/or spill response activities that may arise and any failures to do so may materially adversely impact the Company's financial position, results of operations and cash flows.

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 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 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.

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 explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly increase our risks, costs and delays.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 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 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 former BOEMRE issued a series of active 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, OCS waters and shallow waters, where we have substantial operations, must comply with strict new safety and operating requirements. For example, permit applications for drilling projects must meet new standards with respect to well design, casing and cementing, blowout preventers, safety certification, emergency response, and worker training. Operators of all offshore waters are also required to demonstrate the availability of

adequate spill response and blowout containment resources. In addition, the BSEE imposed, for the first time, requirements that offshore operators maintain comprehensive safety and environmental programs. Such developments have the potential to increase our costs of doing business. Notwithstanding the lifting of the moratorium on October 12, 2010, there have been significant delays in permitting and an overall decline in the number of permits that have been issued. We anticipate that there will continue to be delays in permitting as these and possible additional 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 new regulatory requirements, 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. We are not able to predict the likelihood of such proposals actually becoming law or the nature, extent or timing of any interim or final rules that may result from such proposals. If enacted, such 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, there have been proposals in the U.S. Congress to amend OPA, including by eliminating limits on liability and further increasing applicable financial assurance requirements, in response to the Deepwater Horizon incident. If OPA were 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 or when any such changes in current laws and regulations will occur.

Recent hurricanes in the Gulf of Mexico, including Ivan, Katrina, Rita, Gustav and Ike, caused damage to a number of unaffiliated drilling rigs. BOEM and BSEE issued guidelines imposing new requirements relating to tie-downs on drilling rigs and other permanent equipment attached to outer continental shelf production platforms to increase the likelihood of survival of such rigs during hurricane events. The guidelines also impose new data collection and disclosure requirements. Such hurricane protection measures, and any new or more stringent guidelines or formal rules, may subject our operations to increased costs or limit operational capabilities during storm events.

The recent reorganization of the former BOEMRE may impact potential future regulations or enforcement that may affect our operations.

On October 1, 2011, the U.S. Department of the Interior completed its reorganization of the BOEMRE (formerly the Minerals Management Service) by dividing its offshore oil and gas responsibilities among three independent agencies. The first phase of reorganization took place in 2010 when the revenue collection arm of the former Minerals Management Service became the Office of Natural Resources Revenue. A year later the BOEMRE was replaced with the BOEM, which has responsibility for leasing and environmental studies, and the BSEE, which has responsibility for field operations, including inspections, regulatory compliance, and oil spill response. 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 applicable regulations, which, if required, could be costly and reduce borrowings available under our credit facility or any other credit facilities we may enter into in the future.

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 OCS of the Gulf of Mexico and removal of facilities. Lessees subject to these regulations are generally required to 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 such supplemental bonding requirements, the BOEM or BSEE could re-evaluate or increase our obligations, 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 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. Such laws regulate, among other things, air emissions, water and stormwater discharges, releases of oil and hazardous substances and the development, implementation, inspection and maintenance of emergency response procedures. 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, including possible suspension of our operations. Certain environmental laws impose strict liability for remediation of spills and releases of oil and hazardous substances, as well as for any resulting damage to natural resources, and can include claims by private parties as well as governmental agencies.

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.

In addition, we are required to satisfy insurance and financial responsibility requirements for potential oil spills and other pollution incidents. While our current insurance for such events is consistent with the requirements of OPA, there is no assurance that such coverage will continue to be available in the future or that we will be able to obtain such insurance. Even if insurance is available and we have obtained coverage, the insurance coverage may not be adequate to satisfy all resulting liabilities should a significant claim occur. Any of these scenarios could have a material adverse effect on our business, operating results and financial condition.

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 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, but has not passed, legislation that seeks to control or reduce emissions of greenhouse gases from a variety of sources. In addition, several states have taken measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories or state-specific 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.

In the absence of federal legislation, the EPA is implementing regulations under the Clean Air Act pertaining to greenhouse gas emissions. In 2009, the EPA issued a finding that greenhouse gas pollution endangers the public health and welfare and subsequently finalized a greenhouse gas emission standard for mobile sources. On November 8, 2010, the EPA 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. Challenges to certain of those greenhouse gas rules were rejected by the D.C. Circuit Court of Appeals. Requests to reconsider are pending but, for the present, implementation seems likely although such rules may yet be modified 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 be assured 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.

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 former BOEMRE communicated that it would 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 former 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 former BOEMRE stated that these measures were in response to recent hurricane seasons in which idle structures were damaged or destroyed. In 2011, we 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." We periodically review our plans with the BSEE to perform wellbore plugging and abandonment and decommissioning work on certain facilities and structures in our East Bay field.

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

The failure to comply with these rules and regulations can result in substantial penalties, including lease termination in the case of federal leases. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to

the same regulatory requirements and restrictions that affect our operations, though the impact of those requirements may vary significantly based on the nature and location of operations and related pipelines and facilities.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

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

The enactment of derivatives legislation by Congress could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide derivative transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Columbia in September 2012, although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of “swap”, “security-based swap”, “swap dealer” and “major swap participant.” The Dodd-Frank Act and the CFTC rules also will require us, in connection with certain derivative activities, to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and the CFTC rules on us and the timing of such effects. The Dodd-Frank Act also may 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 Dodd-Frank Act 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 Dodd-Frank Act and regulations implementing the Dodd-Frank Act, 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 Dodd-Frank Act 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 gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The proposed U.S. federal budget for fiscal year 2013 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

The 2013 fiscal budget proposed by the Obama administration would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new taxes. The proposed provisions include: the elimination of current deductions for intangible drilling and development costs; the repeal of the percentage depletion allowance for oil and gas properties; the extension of the amortization period for certain geological and geophysical

expenditures; and the elimination of the deduction for certain U.S. production activities.

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 cash flows. This could also reduce our drilling activities. Since none of these proposals has yet become law, we do not know the ultimate impact any of these proposals may have on our business.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber attack directed at oil and gas distribution systems could damage critical

distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. We have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. Although historically we have not incurred material expenditures for protective measures related to potential cyber attacks, as cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber attacks.

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 13, “Commitments and Contingencies” in the consolidated financial statements in Part II, Item 8 of this Annual Report.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common stock is listed on the New York Stock Exchange (“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.

	High ($)	Low ($)
2011		
First Quarter	18.21	13.79
Second Quarter	18.56	13.69
Third Quarter	18.08	10.36
Fourth Quarter	16.05	9.99
2012		

First Quarter	18.49	14.72
Second Quarter	17.53	14.56
Third Quarter	21.99	16.01
Fourth Quarter	23.28	19.31
2013		
First Quarter (through February 28, 2013)	26.28	25.71

On February 28, 2013, the last reported sales price of our common stock on the NYSE was $25.73 per share.

As of February 28, 2013, there were approximately 159 holders of record of our common stock.

We have not paid cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including our credit facility and the Indentures 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.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2012 with respect to compensation plans under which our equity securities are authorized for issuance.

	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(3)
Equity compensation plans approved by stockholders (4)	554,587	$ 16.98	679,608
Equity compensation plans not approved by stockholders (5)	964,523	$ 13.26	-
Total	1,519,110	$ 14.30	679,608

(1) Comprised of 1,192,158 shares subject to issuance upon the exercise of options and 326,952 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) These shares are available for future issuance under the 2009 Long Term Incentive Plan, as amended, in the form of options, appreciation rights, restricted shares, deferred shares, bonus stock and performance shares, units or restricted stock units.

(4) At our 2011 Annual Meeting of Stockholders, our stockholders approved an increase in the number of shares authorized for issuance into the 2009 Long Term Incentive Plan from 1,237,000 shares to 2,474,000 shares.

(5) The form of the 2009 Long Term Incentive Plan was filed with the supplement to our plan of reorganization and approved by the United States Bankruptcy Court for the Southern District of Texas prior to our emergence from Chapter 11 reorganization on September 21, 2009. Accordingly, no stockholder approval was required, and none was sought or obtained.

See Note 12 “Employee Benefit Plans” of the consolidated financial statements in Part II, Item 8 of this Annual Report for further information regarding the material features of the above plan.

Stock Performance Graph

This information is being “furnished” to the SEC and is not deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities of Section 18 of the Exchange Act, and will not be deemed to be incorporated by reference into any filings we make under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent we specifically incorporate it be reference into such a filing.

The following graph compares the cumulative total shareholder return on our common stock relative to the cumulative total returns of the Russell 2000 index and a customized peer group described below. The graph tracks the performance of a $100 investment in our common stock, in the customized peer group, and the index (with reinvestment of all dividends) from September 30, 2009, the end of the first month in which we emerged from Chapter 11 bankruptcy proceedings, through December 31, 2012. Because the value of our old common stock bears no relation to the value of our existing common stock, the graph below reflects only our new common stock. The historic price performance is not necessarily indicative of future stock performance.

	9/30/09	12/31/09	12/31/10	12/31/11	12/31/12
EPL Oil & Gas, Inc	100.00	114.61	199.20	195.71	302.28
Russell 2000	100.00	103.87	131.77	126.27	146.91
2012 Peer Group	100.00	107.83	169.52	171.18	156.57

Our peer group includes: ATP Oil & Gas Corporation, Energy XXI (Bermuda) Limited, McMoRan Exploration Company, Stone Energy Corporation and W & T Offshore, Inc.

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				Predecessor Company (1)	
	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010	Period from October 1, 2009 through December 31, 2009	Period from January 1, 2009 through September 30, 2009	Year Ended December 31, 2008
	(In thousands, except per share data)					
Statement of Operations Data:						
Revenue	$ 423,633	$ 348,327	$ 239,909	$ 56,750	$ 134,885	$ 356,252
Income (loss) from operations (2)	130,447	67,126	7,309	(4,523)	(51,323)	(25,531)
Net income (loss)	58,810	26,611	(8,468)	(21,012)	(36,114)	(52,212)
Basic earnings (loss) per common share	$ 1.50	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)	$ (1.63)
Diluted earnings (loss) per common share	$ 1.50	$ 0.66	$ (0.21)	$ (0.53)	$ (1.12)	$ (1.63)

	Successor Company As of December 31,				Predecessor Company (1) As of December 31,
	2012	2011	2010	2009	2008
	(In thousands)				
Balance Sheet Data:					
Total assets (3)	$ 1,705,627	$ 915,220	$ 626,906	$ 709,228	$ 766,766
Long-term debt, excluding current maturities(3) (4)	689,911	204,390	-	58,590	-
Stockholders’ equity	545,973	491,045	473,116	480,087	57,119
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) The loss from operations in 2008 includes business interruption insurance recoveries of $4.2 million from deferred production at our covered fields resulting from Hurricanes Gustav and Ike in 2008.

(3) During the year ended December 31, 2012, we acquired the Hilcorp Properties and the ST41 Interests. In connection with the Hilcorp Acquisition, we issued the 2012 Senior Notes. During the year ended December 31, 2011, we acquired the ASOP Properties and Main Pass Interests. In connection with the ASOP Acquisition, we issued the 2011 Senior Notes.

(4) At December 31, 2012 and 2011, none of our debt was classified as current. At December 31, 2010, we had no borrowings outstanding. At December 31, 2009 and 2008, long-term debt classified as current was $18.8 million and $497.5 million, respectively.

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 expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations. As of December 31, 2012, we had estimated proved reserves of 77.4 million barrels of oil equivalent, or Mmboe, of which 61% were oil and 75% were proved developed. Of these proved developed reserves, 65% were oil reserves.

2012 Acquisitions

On October 31, 2012, we acquired from Hilcorp Energy GOM Holdings, LLC ("Hilcorp") 100% of the membership interests of Hilcorp Energy GOM, LLC ("Hilcorp Acquisition"), which owned certain shallow water Gulf of Mexico shelf oil

and natural gas interests (the "Hilcorp Properties"), for $550 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. As of December 31, 2012, the Hilcorp Properties had estimated proved reserves of approximately 37.2 Mmboe, of which 49% were oil and 58% were proved developed reserves.

The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of $300 million in aggregate principal amount of 8.25% senior notes due 2018 (the "2012 Senior Notes") and borrowings under our Senior Credit Facility. The 2012 Senior Notes were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the Securities Act of 1933, as amended (the "Securities Act"), or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. After deducting the initial purchasers' discount, we realized net proceeds of $289.5 million. Also on October 31, 2012, we obtained an increase in our Senior Credit Facility from $250 million to $750 million under which we borrowed $205 million to fund a portion of the purchase price and related expenses of the Hilcorp Acquisition. The Hilcorp Properties include the three core complexes of Ship Shoal 208, South Pass 78 and South Marsh Island 239 which are described in Part I, Item 1, "Business – Properties."

In the June 20, 2012, Central Gulf of Mexico Lease Sale 216/222, we were the high bidder on six leases covering a total of 27,148 acres on a gross and net basis located in the shallow Gulf of Mexico shelf within our core area of operations. Our share of the high bids totaled approximately $7.0 million.

On May 15, 2012, we acquired from W&T Offshore, Inc. ("W&T") an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests in our South Timbalier 41 field ("ST41 Interests") located in the Gulf of Mexico for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012 (the "ST41 Acquisition"). Prior to the ST41 Acquisition, we owned a 60% working interest in the properties, and W&T owned a 40% working interest. As a result of the ST41 Acquisition, we have become the sole working interest owner of the South Timbalier 41 field. The ST41 Interests had estimated proved reserves as of the acquisition date of approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. We funded the ST41 Acquisition with cash on hand.

These acquisitions significantly increased 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. They have also provided us with access to infrastructure and extensive acreage, with significant exploitation and development potential. We intend to pursue exploration and exploitation of these properties, including recompletions, well reactivations and development drilling. In conjunction with the Hilcorp Acquisition, we implemented a three-year commodity price hedging program weighted towards oil to help reduce commodity price risks associated with future oil production.

Overview and Outlook

During 2012, we spent approximately $223 million on development activities and exploration projects within existing core field areas, including seismic purchases of approximately $11 million. We recently acquired additional 2-D and 3-D seismic data sets in our current offshore operating areas and onshore Louisiana where the geology is characterized by similar productive horizons and structural features. We also spent $7 million on the recently bid leases in the shallow Gulf of Mexico shelf. Additionally, we spent approximately $35 million in 2012 on plugging, abandonment and other decommissioning activities. Our fiscal year 2013 capital budget is $300 million, which is allocated to development activities and exploration projects within existing core fields. Additionally, we plan to spend approximately $30 million in 2013 on plugging, abandonment and other decommissioning activities. We budget our capital spending on exploration and development with the goal of remaining within cash flow from operations, allowing free cash flow from current and acquired assets to reduce debt.

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 assets in the Gulf of Mexico and the Gulf Coast region that are characterized by production-weighted

reserves, seismic coverage, operated positions and the ability to consolidate interests in existing properties. 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 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 exploration and development costs and operating costs to remain competitive with our offshore Gulf of Mexico industry peers.

We believe that our core competency in plugging, abandonment and decommissioning operations 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 lease operating expenses ("LOE") associated with maintaining idle infrastructure.

Results of Operations

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

	Year Ended December 31,		
	2012	2011	2010
Net production (per day):			
Oil (Bbls)	10,398	8,089	6,401
Natural gas (Mcf)	17,852	17,968	42,488
Total (Boe)	13,373	11,084	13,482
Average sales prices:			
Oil (per Bbl)	$ 106.08	$ 108.81	$ 72.80
Natural gas (per Mcf)	2.89	4.11	4.49
Total (per Boe)	86.33	86.07	48.72
Oil and natural gas revenues (in thousands):			
Oil	$ 403,663	$ 321,275	$ 170,079
Natural gas	18,866	26,932	69,691
Total	422,529	348,207	239,770
Impact of derivatives instruments settled during the period [(1)]:			
Oil (per Bbl)	$ (0.88)	$ (5.87)	$ (3.62)
Natural gas (per Mcf)	(0.07)	-	0.01
Average costs (per Boe):			
LOE	$ 19.38	$ 17.37	$ 10.64
Depreciation, depletion and amortization ("DD&A")	23.21	25.86	21.25
Accretion of liability for asset retirement obligations	3.18	3.94	2.61
Taxes, other than on earnings	2.66	3.55	2.06
General and administrative ("G&A") expenses	4.74	4.63	3.67
Increase (decrease) in oil and natural gas revenues due to:			
Changes in prices of oil	$ (8,055)	84,146	
Changes in production volumes of oil	90,443	67,050	
Total increase in oil sales	82,388	151,196	
Changes in prices of natural gas	$ (7,995)	(5,904)	
Changes in production volumes of natural gas	(71)	(36,855)	
Total decrease in natural gas sales	(8,066)	(42,759)	

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

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Overview

During the year ended December 31, 2012, we completed twelve (12) development drilling operations, eleven (11) of which were successful, and eighteen (18) recompletion operations, sixteen (16) of which were successful. We also completed three (3) exploratory drilling operations, one of which was successfully completed in a development zone.

Our operating results for the year ended December 31, 2012, compared to the year ended December 31, 2011, reflect a 29% increase in oil production, partially offset by lower average selling prices for our oil and natural gas. Our product mix for the year ended December 31, 2012 was 78% oil (including natural gas liquids) compared to 73% for the year ended December 31, 2011. Production from the acquired Hilcorp Properties, ST41 Interests, ASOP Properties and Main Pass Interests had an impact of approximately 6,648 Boe per day on the production rate for the year ended December 31, 2012, compared to results for the year ended December 31, 2011, which include production from the ASOP Properties for the period from February 14, 2011 to December 31, 2011, reflecting only a 3,283 Boe per day impact on the production rate in the prior period.

For the year ended December 31, 2012, our total revenue increased 22% as compared to the year ended December 31, 2011, due primarily to the 29% increase in oil production. Our overall production volumes increased 21% for the year ended December 31, 2012 when compared to the year ended December 31, 2011. Our Gulf of Mexico shelf production, excluding the recently acquired Hilcorp Properties, increased 10% in the year ended December 31, 2012, as compared to the year ended

December 31, 2011, due primarily to production increases in our West Delta field and production from other ASOP Properties, the Main Pass Interests and the ST41 Interests, partially offset by production declines in our predominantly natural gas fields. The Hilcorp Properties contributed 1,488 Boe per day to our production rate for the year ended December 31, 2012, producing approximately 8,944 Boe per day from November 1, 2012 through December 31, 2012. Our deepwater production, primarily natural gas, was curtailed during the year ended December 31, 2012 due to third party downstream facility modifications.

In addition to the items addressed above, our net income for the year ended December 31, 2012 includes exploration expenditures, primarily due to area-wide 2-D and 3-D seismic purchases totaling $10.6 million, impairments of $8.9 million and a net loss on derivative instruments of $13.3 million. The net income for the year ended December 31, 2011 reflects impairments of $32.5 million, a net loss on derivative instruments of $5.9 million and a $2.4 million loss on early extinguishment of debt as a result of the termination of our prior credit facility.

Our effective income tax rate for the year ended December 31, 2012 was 33.7%. The income tax expense that we recorded (all of which was deferred) for the year ended December 31, 2012 was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.3% in 2011 to 36.4% in 2012 was primarily related to estimated state income taxes. The effective income tax rate for the year ended December 31, 2011 was 35.8%. The income tax expense (all of which was deferred) that we recorded for the year ended December 31, 2011 was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.6% in 2010 to 37.3% in 2011 was primarily related to estimated state income taxes.

Revenue and Net Income

	Year Ended December 31,			
	2012	2011		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 422,529	$ 348,207	$ 74,322	21%
Net income	58,810	26,611	32,199	121%

Our oil and natural gas revenues increased primarily as a result of the 29% increase in oil production in the year ended December 31, 2012, as compared to the year ended December 31, 2011, offset in part by a 3% decline in average selling prices for our oil and a 30% decline in average selling prices for our natural gas in the year ended December 31, 2012, as compared to the year ended December 31, 2011. Oil represented 78% of total production for the year ended December 31, 2012, as compared to 73% of total production for the year ended December 31, 2011. We expect our oil and natural gas production to increase in 2013 due to the acquisition of the Hilcorp Properties and the increase in our capital expenditure budget for 2013.

Operating Expenses

Our operating expenses primarily consisted of the following:

	Year Ended December 31,			
	2012	2011		
	(in thousands)		$ Change	% Change
LOE	$ 94,850	$ 70,281	$ 24,569	35%
Exploration expenditures and dry hole costs	18,799	14,268	4,531	32%
Impairments	8,883	32,466	(23,583)	-73%
DD&A, including accretion expense	129,146	120,566	8,580	7%
G&A expenses	23,208	18,741	4,467	24%
Taxes, other than on earnings	13,007	14,365	(1,358)	-9%

LOE increased for the year ended December 31, 2012, compared to the year ended December 31, 2011, primarily due to the 2011 acquisitions of the ASOP Properties and Main Pass Interests and the 2012 acquisitions of the Hilcorp Properties and the ST41 Interests and approximately $3.0 million of expenses related to Hurricane Isaac in the 2012 period. We expect our LOE to increase materially in 2013 due to the acquisition of the Hilcorp Properties.

We recorded approximately $4.2 million of dry hole costs, primarily associated with two exploratory wells, which were drilling at December 31, 2011, reached their target depths in January 2012 and were determined to be unsuccessful and an unsuccessful exploratory portion of a well that was successfully completed in a development zone. In addition, exploration expenditures during the year ended December 31, 2012 include $10.6 million of seismic expense. We recorded approximately $11.2 million of dry hole costs associated with unsuccessful wells in the year ended December 31, 2011. In

the year ended December 31, 2011, we completed drilling five exploratory wells, one of which was unsuccessful. In addition, exploration expenditures in the year ended December 31, 2011 includes $0.8 million of seismic expenditures and delay rentals. Our exploratory expenditures and dry hole costs will vary significantly depending on the amount of our capital expenditures dedicated to exploration activities and the level of success we achieve in exploratory drilling activities.

Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that are expiring in 2013 for which we have no development plans. Impairments for the year ended December 31, 2011 were primarily related to natural gas producing fields and our deepwater producing well (primarily natural gas). Impairments related to our deepwater producing well were primarily due to the decline in our estimate of future natural gas prices, reservoir performance and higher estimated operating costs. Additional impairments for the year ended December 31, 2011 were primarily related to reservoir performance at other natural gas producing fields. We periodically assess our oil and natural gas assets for impairment based on factors described in "—Discussion of Critical Accounting Policies." The factors that can result in impairment include declines in the estimated future selling prices of oil and natural gas.

G&A expenses increased for the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily as a result of an increase in employee-related costs, including an increase in non-cash share-based compensation, which was $4.7 million in the 2012 period as compared to $2.5 million in the year ended December 31, 2011. We expect an increase in our G&A expenses in 2013, primarily due to an increase in non-cash share-based compensation.

Taxes, other than on earnings, were lower in the year ended December 31, 2012, as compared to the year ended December 31, 2011. The decrease is primarily related to severance taxes and a decrease in production from state leases (which is subject to a severance tax regime).

Other Income and Expense

Interest expense increased in the year ended December 31, 2012, as compared to the year ended December 31, 2011. For the year ended December 31, 2012, our interest expense includes interest on our 2012 Senior Notes and the Senior Credit Facility since the time of the issuance of the 2012 Senior Notes and borrowings on the Senior Credit Facility during late October 2012 in connection with the Hilcorp Acquisition as well as interest on the 2011 Senior Notes. For the year ended December 31, 2011, our interest expense consists primarily of interest on our 2011 Senior Notes issued on February 14, 2011 in connection with the ASOP Acquisition. We expect our interest expense in 2013 to increase materially due to interest on our 2012 Senior Notes and borrowings on our Senior Credit Facility.

Other income (expense) in the year ended December 31, 2012 includes a net loss on derivative instruments of $13.3 million consisting of an unrealized loss of $9.5 million due to the change in fair market value of derivative instruments and a realized loss of $3.8 million on derivative instruments settled during the quarter primarily from the impact of higher oil prices during 2012 on our oil fixed-price swaps. Other income (expense) in the year ended December 31, 2011 includes a net loss of $5.9 million consisting of an unrealized gain of $11.5 million due to the change in fair market value of derivative instruments and a loss of $17.4 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2011 on our oil fixed-price swaps.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Overview

During the year ended December 31, 2011, we completed five (5) development drilling operations, four (4) of which were successful; twenty-seven (27) recompletion operations, twenty-three (23) of which were successful; and five (5) exploratory drilling operations, four (4) of which were successful. As of December 31, 2011, we were drilling two (2) additional exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful.

Our operating results for the year ended December 31, 2011, compared to the year ended December 31, 2010, reflect significantly higher average selling prices for our oil partially offset by lower average selling prices for our natural gas. The product mix for our production for the year ended December 31, 2011 was 73% oil (including natural gas liquids), compared to 47% oil (including natural gas liquids) for the comparable period in 2010. This change in product mix results from declines in production of natural gas and natural gas liquids, partially offset by an increase in oil production. Additionally, our results include production from the ASOP Properties and Main Pass Interests, which were acquired during 2011, of 3,283 Boe per day for the year ended December 31, 2011.

For the year ended December 31, 2011, our revenues increased 45% as compared to the year ended December 31, 2010, due primarily to the higher oil sales prices and the increase in oil production. Our overall production volumes, including barrel of oil equivalent natural gas volumes, decreased by 18% for the year ended December 31, 2011 when compared to the year ended December 31, 2010. Our Gulf of Mexico shelf production decreased 13% in the year ended

December 31, 2011, as compared to the year ended December 31, 2010, due primarily to production declines in our predominantly natural gas fields, partially offset by production from the ASOP Properties. In addition, our deepwater production, primarily natural gas, declined 58% for the year ended December 31, 2011, as compared to the year ended December 31, 2010, due to natural reservoir decline from our deepwater well and curtailed production for extended periods during the third and fourth quarters of 2011, and continuing through the first quarter of 2012, due to third party downstream facility modifications.

Our effective income tax rate for the year ended December 31, 2011 was 35.8%. The income tax expense (all of which is deferred) that we recorded for the year ended December 31, 2011 was reduced due to applying the change in our estimated effective income tax rate to our net deferred tax liabilities. The change in our estimated effective income tax rate from 37.6% in 2010 to 37.3% in 2011 was primarily related to estimated state income taxes. Our effective income tax rate for the year ended December 31, 2010 was 34.2%. The income tax benefit recorded on the net loss for the year ended December 31, 2010 was reduced due to our applying the change in our estimated effective income tax rate for the full year 2010, from 36% to 37.6%, to our net deferred tax liabilities. The change in our estimated effective income tax rate for 2010 was primarily related to state income taxes.

Revenue and Net Income (Loss)

	Year Ended December 31,			
	2011	2010		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 348,207	$ 239,770	$ 108,437	45%
Net income (loss)	26,611	(8,468)	35,079	NM

NM—Not Meaningful

Our oil and natural gas revenues increased primarily due to a 49% increase in average selling prices for our oil and a 26% increase in oil production in the year ended December 31, 2011 as compared to the year ended December 31, 2010, offset in part by a 58% decline in natural gas production and a 8% decline in average selling prices for our natural gas in the year ended December 31, 2011 as compared to the year ended December 31, 2010. Oil represented 73% of total production for the year ended December 31, 2011, as compared to 47% of total production for the year ended December 31, 2010.

Operating Expenses

Our operating expenses primarily consisted of the following:

	Year Ended December 31,			
	2011	2010		
	(in thousands)		$ Change	% Change

LOE	$ 70,281	$ 52,365	$ 17,916	34%
Exploration expenditures and dry hole costs	14,268	6,441	7,827	122%
Impairments	32,466	26,142	6,324	24%
DD&A, including accretion expense	120,566	117,406	3,160	3%
G&A expenses	18,741	18,078	663	4%
Taxes, other than on earnings	14,365	10,133	4,232	42%

LOE increased primarily due to the addition of the ASOP Properties in 2011. The increase in our LOE per Boe is due to the increase in our oil production, which generally has a higher per Boe cost to produce than natural gas, and a decrease in natural gas production and total Boe production.

We recorded approximately $11.2 million of dry hole costs associated with unsuccessful wells in the year ended December 31, 2011. In the year ended December 31, 2011, we completed drilling five exploratory wells, one of which was unsuccessful. As of December 31, 2011, we were drilling two additional exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful. In addition, the expense in the year ended December 31, 2011 includes $0.8 million of seismic expenditures and delay rentals. In the year ended December 31, 2010, we completed drilling two exploratory dry holes and recorded approximately $5.1 million of dry hole costs. In addition, the expense in the year ended December 31, 2010 includes $1.3 million of seismic expenditures and delay rentals.

Impairments for the year ended December 31, 2011 were primarily related to natural gas producing fields and our deepwater producing well (primarily natural gas). Impairments related to our deepwater producing well were primarily due to the decline in our estimate of future natural gas prices, reservoir performance and higher estimated operating costs. Additional impairments for the year ended December 31, 2011 were primarily related to reservoir performance at other natural gas producing fields. Impairments for the year ended December 31, 2010 were primarily related to the decline in our

estimate of future natural gas prices as of September 30, 2010 as compared to June 30, 2010 affecting two producing fields, including our deepwater producing well, and to reservoir performance of one of these fields and one additional producing field.

DD&A per Boe increased primarily due to the acquisition of the ASOP Properties and the Main Pass Interests which have higher per Boe DD&A rates because they were recorded at estimated fair values at their respective 2011 acquisition dates.

G&A expenses increased in the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily as a result of an increase in non-cash share-based compensation and costs incurred in our acquisition efforts, partially offset by decreases in employee related costs. Non-cash share-based compensation was $2.5 million and $1.3 million in the years ended December 31, 2011 and 2010, respectively. Acquisition costs related to the ASOP Acquisition and Main Pass Acquisition totaled approximately $0.6 million in the year ended December 31, 2011.

Taxes, other than on earnings, increased in the year ended December 31, 2011 as compared to the year ended December 31, 2010, due primarily to higher average sales prices for oil (for which production taxes are based on selling price).

Other Income and Expense

Interest expense increased in the year ended December 31, 2011, as compared to the year ended December 31, 2010. For the year ended December 31, 2011, our interest expense consists primarily of interest on our 2011 Senior Notes issued on February 14, 2011 in connection with the ASOP Acquisition. For the year ended December 31, 2010, interest expense consisted primarily of interest expense on our 20% Senior Subordinated Secured PIK Notes due 2014 (the “PIK Notes”) and the term portion of our previous credit facility, which were outstanding during that period. We redeemed all of our outstanding PIK Notes on June 28, 2010.

Other income (expense) in the year ended December 31, 2011 includes a net loss of $5.9 million consisting of an unrealized gain of $11.5 million due to the change in fair market value of derivative instruments and a loss of $17.4 million on derivative instruments settled during the period primarily from the impact of our oil fixed-price swaps. Other income (expense) in the year ended December 31, 2010 includes a net loss of $4.9 million consisting of an unrealized gain of $3.5 million due to the change in fair market value of derivative instruments and a loss of $8.4 million on derivative instruments settled during the period primarily from the impact of our oil fixed-price swaps.

Liquidity and Capital Resources

Sources and Uses of Capital

As of February 28, 2013, we had $240 million available under our Senior Credit Facility, which has a borrowing base of $425 million. Our fiscal year 2013 capital budget is $300 million, which is allocated to development activities and exploration projects within existing core field areas. Additionally, we plan to spend approximately $30 million in 2013 on plugging, abandonment and other decommissioning activities. We intend to finance our capital expenditure budget with cash flow from operations.

On October 31, 2012, in connection with the closing of the Hilcorp Acquisition, our Senior Credit Facility was amended and restated, expanding the facility from $250 million to $750 million and increasing the borrowing base from $200 million to $425 million. As of February 28, 2013, we had $185.0 million outstanding and $240.0 million available under the Senior Credit Facility. See Senior Credit Facility below.

Cash Flow and Working Capital. Net cash provided by operating activities increased to $214 million for the year ended December 31, 2012 compared to $171 million and $127 million for the years ended December 31, 2011 and

2010, respectively. Based on our outlook of commodity prices, our significant hedging program and our estimated production, we expect to fund our 2013 capital expenditures with cash flow from operations and generate free cash flow which could reduce borrowings under our Senior Credit Facility.

Our revenue, profitability, cash flows and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depends on numerous factors beyond our control such as economic conditions, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. Our derivative instruments serve to mitigate a portion of this price volatility on our cash flows. For full year 2013, we have a total of 11,157 Bbls of oil per day hedged, the majority of which is hedged using Brent fixed price swaps at a price averaging $106.01 per Bbl. We have a total of 9,562 Mmbtu of natural gas per day hedged for 2013, all of which is hedged using fixed price swaps at a price averaging $3.51 Mmbtu per day. For full year 2014, we have a total of 8,715 Bbls of oil per day hedged, all of which is hedged using Brent fixed price swaps at a price averaging $101.13 per Bbl. We have a total of 5,000 Mmbtu of natural gas per day hedged for 2014, all of which is hedged using fixed price swaps at a price averaging $4.01 Mmbtu per day. In addition, we have begun hedging

forecasted production for 2015 with 1,500 Bbls of oil per day currently hedged using Brent fixed price swaps at a price of $97.70 per Bbl and 4,300 Mmbtu of natural gas per day currently hedged using fixed price swaps at a price averaging $4.31 Mmbtu per day.

We have incurred, and will continue to incur, capital expenditures to achieve production targets. While we expect to fund future capital expenditures with cash flow from operations, we depend on the availability of borrowings under our Senior Credit Facility as a source of liquidity. Based on anticipated oil and natural gas prices and availability under our Senior Credit Facility, we expect to be able to fund our planned capital expenditures budget, debt service requirements and working capital needs for 2013. In addition to borrowings under our Senior Credit Facility, in order to meet capital requirements, which could include the funding of future acquisitions, we also have the ability to issue debt and equity securities under our universal shelf registration statement that became effective under the Securities Act in July 2011. However, a substantial or extended decline in oil or natural gas prices could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced. Any such extended decline could also have an adverse impact on our ability to issue additional debt or equity securities and our ability to comply with the financial covenants under our Senior Credit Facility, which in turn would limit further borrowings under our Senior Credit Faciltiy.

At December 31, 2012, we had a working capital deficit of $106.3 million, compared to working capital of $10.2 million at December 31, 2011. The working capital deficit at December 31, 2012 is primarily due to the use of cash to fund a portion of the Hilcorp Acquisition and increased accounts payable and accrued expenses related to exploration and development costs. We have experienced, and expect to experience in the future, significant working capital deficits. Our working capital deficits have historically resulted from increased accounts payable and accrued expenses related to ongoing exploration and development costs, which may be capitalized as noncurrent assets, or increased investment in oil and natural gas properties. Additionally, we expect to use any available free cash flow to reduce our debt, all of which is long-term. Therefore, although we may continue to experience working capital deficits, we expect to have significant availability under our Senior Credit Facility, providing substantial liquidity.

Capital Expenditures. During the year ended December 31, 2012, we incurred costs of approximately $223.1 million on development and exploration activities, including $10.6 million on the seismic purchases previously described. We also spent $7.4 million on the recently bid leases in the shallow Gulf of Mexico shelf. In addition, we spent approximately $35.4 million on plugging, abandonment and other decommissioning activities during the year ended December 31, 2012.

Acquisition and Dispositions. On October 31, 2012, we acquired the Hilcorp Properties for $550 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of $300 million in aggregate principal amount of the 2012 Senior Notes and borrowings of $205 million under our Senior Credit Facility. On May 15, 2012, we acquired the remaining 40% working interest in our South Timbalier 41 field for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012. We funded the ST41 Acquisition with cash on hand. We may fund future acquisitions with a combination of cash on hand, borrowings on our Senior Credit Facility and issuances of one or more debt and equity securities under our universal shelf registration statement that became effective under the Securities Act in July 2011.

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. This allocation has led us to focus on oil-weighted projects, which has resulted in a trend of increasing oil production. From time to time, we may decide to divest of certain oil and gas properties that do not meet our capital expenditure risk, rate of return, operational control or other criteria. In addition to the pending sale of the non-operated Bay Marchand properties described in “Business—Recent Events,” we are currently trying to determine whether there would be any interest for other small packages of our assets. However, there can be no assurance that any such small asset packages will be sold or, if so, on what terms.

Share Repurchase Program. In August 2011, the board of directors authorized a program for the repurchase of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million and increased the program to $40.0 million in May 2012. Under the program, we have repurchased 1,465,300 shares at an aggregate cash purchase price of approximately $20.1 million, including 446,300 shares purchased for approximately $7.3 million during 2012. Such shares are held in treasury and could be used to provide available shares for possible resale in future public or private offerings and our employee benefit plans. The repurchases have been, and will be, carried out in accordance with certain volume, timing and price constraints imposed by the SEC's rules applicable to such transactions. The amount, timing and price of purchases otherwise depend on market conditions and other factors.

Restricted Cash. We maintain restricted escrow funds in a trust for future plugging, abandonment and other decommissioning costs at our East Bay field. The trust was originally funded with $15.0 million and, with accumulated interest, had increased to $16.7 million at December 31, 2008. We have made draws to date of $10.7 million. We were able to draw from the trust upon the authorization, and subsequent completion, of qualifying abandonment activities at our East

Bay field. As of December 31, 2012, we had $6.0 million remaining in restricted escrow funds in the trust for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our condensed consolidated balance sheets.

The BOEM, the BSEE 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. For important additional information regarding risks related to our regulatory environment, see Part I, Item 1A, “Risk Factors.”

2011 Senior Notes. On February 14, 2011, we issued $210 million in aggregate principal amount of the 2011 Senior Notes. We used the net proceeds from the offering of the 2011 Senior Notes of $202 million, after deducting the initial purchasers’ discount and estimated offering expenses payable by us, to acquire the ASOP Properties for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011, and for general corporate purposes. The 2011 Senior Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due on outstanding notes payable semi-annually, in arrears, on February 15th and August 15th of each year, commencing on August 15, 2011. The 2011 Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct domestic subsidiaries (other than immaterial subsidiaries). The 2011 Senior Notes will mature on February 15, 2018. For more information on our 2011 Senior Notes, see Note 7, “Indebtedness,” of our consolidated financial statements contained in Part II, Item 8 of our this Annual Report.

2012 Senior Notes. On October 25, 2012, we issued the $300 million in aggregate principal amount of our 2012 Senior Notes. We used the net proceeds from the offering of the 2012 Senior Notes of $289.5 million, after deducting the initial purchasers’ discount, to fund a portion of the Hilcorp Acquisition. The 2012 Senior Notes bear interest from August 15, 2012 at an annual rate of 8.25% with interest due semi-annually, in arrears on February 15th and August 15th of each year commencing on February 15, 2013. The 2012 Senior Notes are fully and unconditionally guaranteed on a senior basis initially by each of our existing direct domestic subsidiaries (other than immaterial subsidiaries). The 2012 Senior Notes mature on February 15, 2018.

The 2012 Senior Notes have terms that are substantially identical to the terms of our 2011 Senior Notes, other than with respect to special mandatory redemption provisions related to the closing of the Hilcorp Acquisition. (Such provisions are now inapplicable because the Hilcorp Acquisition has closed). However, the 2012 Senior Notes were issued under a different indenture than the 2011 Senior Notes as a separate class of securities and therefore, until exchanged for publicly registered notes, will not trade together with the 2011 Senior Notes. Pursuant to a registration rights agreement executed as part of the sale of the 2012 Senior Notes, we have agreed to issue publicly registered additional notes under our indenture dated February 14, 2011 in exchange for the 2012 Senior Notes. For more information regarding the 2012 Senior Notes, see Note 7, “Indebtedness”, of our condensed consolidated financial statements in Part II, Item 8 of this Annual Report.

Senior Credit Facility. On February 14, 2011, we entered into our Senior Credit Facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto. The terms of our Senior Credit Facility established a revolving credit facility with a four-year term that could be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million. On October 31, 2012, in connection with the Hilcorp Acquisition, through an amendment and restatement of our Senior Credit Facility, the aggregate commitment under this facility was increased to a maximum of $750.0 million and the maturity date was extended to October 31, 2016. The maximum amount of letters of credit that may be outstanding at any one time is $20.0 million. The amount available under the revolving credit facility is limited by the borrowing base. The Senior Credit Facility is secured by substantially all of our assets, including a) mortgages on at least 80% of the total

value of our oil and gas properties evaluated in the most recently completed reserve report, after giving effect to exploration and production activities, acquisitions and dispositions, and b) the stock of certain wholly-owned subsidiaries. The borrowing base under our Senior Credit Facility has been determined at the discretion of the lenders, based on the collateral value of our proved reserves and the proved reserves of the Hilcorp Properties, and is subject to potential special and regular semi-annual redeterminations. On October 31, 2012, the borrowing base under the expanded credit facility was increased from $200.0 million to $425.0 million. Borrowings under our Senior Credit Facility bear interest ranging from a base rate plus a margin of 0.75% to 1.75% on base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% on LIBOR borrowings. Commitment fees ranging from 0.375% to 0.50% are payable on the unused portion of the borrowing base. On October 31, 2012, we borrowed $205.0 million under the Senior Credit Facility to fund a portion of the purchase price and related expenses of the Hilcorp Acquisition. As of February 28, 2013, we had $185.0 million outstanding and $240.0 million in availability under our Senior Credit Facility. For additional information regarding our Senior Credit Facility, see Note 7, “Indebtedness,” of this Annual Report.

Terminated Credit Facility. On February 14, 2011, we terminated the then existing credit facility in connection with entering into our current credit facility described above, resulting in a loss on early extinguishment of debt of $2.4 million, primarily due to writing off the unamortized deferred financing costs associated with the terminated facility.

Analysis of Cash Flows for the Year Ended December 31, 2012

The following table sets forth our cash flows:

	Years Ended December 31,	
	2012	2011
	(In thousands)	
Net cash provided by operating activities	$ 213,871	$ 171,252
Net cash used in investing activities	(764,965)	(310,591)
Net cash provided by financing activities	472,487	185,914

The increase in our 2012 cash flows from operating activities primarily reflects increases in revenues due to the increase in our oil production, partially offset by decreases in natural gas revenues during the year ended December 31, 2012, as compared to the year ended December 31, 2011.

Net cash used in investing activities increased in the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to our acquisitions of the Hilcorp Properties and the ST41 Interests during the year ended December 31, 2012. In addition, our exploration and development expenditures were higher in the year ended December 31, 2012, due to our higher 2012 capital expenditures budget. These increases were partially offset by our acquisitions of the ASOP Properties and Main Pass Interests during the year ended December 31, 2011.

Net cash provided by financing activities during the year ended December 31, 2012 reflects $294.3 million of net cash proceeds from the issuance of the 2012 Senior Notes (including $4.8 million of accrued interest included in the purchase price of the 2012 Senior Notes) and $215.0 million in borrowings under our Senior Credit Facility, partially offset by repayments of $20.0 million on our Senior Credit Facility, expenditures of $8.5 million for financing costs primarily associated with our Senior Credit Facility and offering expenses associated with our 2012 Senior Notes and $8.8 million for settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program. Net cash provided by financing activities during the year ended December 31, 2011 reflects $203.8 million of net cash proceeds (before offering expenses of $1.8 million) from the issuance of the 2011 Senior Notes, partially offset by expenditures of $6.6 million for financing costs primarily associated with our Senior Credit Facility and offering expenses associated with the 2011 Senior Notes. During the year ended December 31, 2011, we also spent $11.4 million for settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program.

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 Senior Credit Facility, the Original Indenture and the Indenture, 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.

Analysis of Cash Flows for the Year Ended December 31, 2011

The following table sets forth our cash flows:

	Years Ended December 31,	
	2011	2010
	(In thousands)	
Net cash provided by operating activities	$ 171,252	$ 127,380
Net cash used in investing activities	(310,591)	(45,903)
Net cash provided by (used in) financing activities	185,914	(74,669)

The increase in our 2011 cash flows from operations primarily reflects increases in revenues due to the increase in oil prices and our oil production, partially offset by decreases in revenues due to the decline in natural gas production during the year ended December 31, 2011 as compared to the year ended December 31, 2010. In addition, cash flows from operations reflects increased spending on plugging, abandonment and decommissioning activities during the year ended December 31, 2011, as compared to the year ended December 31, 2010.

Net cash used in investing activities increased in the year ended December 31, 2011 as compared to the year ended December 31, 2010, primarily as a result of our acquisitions of the ASOP Properties and the Main Pass Interests and an increase in our exploration and development expenditures during the year ended December 31, 2011.

Net cash provided by financing activities during the year ended December 31, 2011 reflects $203.8 million of net cash proceeds (before offering expenses of $1.8 million) from the issuance of the 2011 Senior Notes, partially offset by expenditures of $6.6 million for financing costs primarily associated with our Senior Credit Facility and offering expenses associated with our 2011 Senior Notes. We also spent $11.4 million for settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program during the year ended December 31, 2011. Net cash used in financing activities during the year ended December 31, 2010 reflects the redemption of the PIK Notes and payments on the term loan component of our amended prior credit facility, partially offset by proceeds from the term loan component of our amended prior credit facility.

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 temporary 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 cost of these materials and services has returned to higher levels due to sustained higher oil prices and the reallocation of capital and related equipment to onshore drilling activities. The duration and extent of future price changes, declines or increases, is highly uncertain.

Disclosures about Contractual Obligations and Commercial Commitments

The following table aggregates the contractual commitments and commercial obligations which affect our financial condition and liquidity position as of December 31, 2012.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	Thereafter
	(in thousands)				
Long-term debt	$ 705,000	$ -	$ -	$ 195,000	$ 510,000
Interest on indebtedness	247,858	46,365	92,730	87,725	21,038
Operating leases	3,866	894	1,921	1,051	-
Asset retirement obligations (undiscounted)	499,456	30,179	66,708	36,002	366,567
Total contractual obligations	$ 1,456,180	$ 77,438	$ 161,359	$ 319,778	$ 897,605

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as of December 31, 2012, other than the operating leases disclosed above.

Derivative Instruments

Note 1 “Organization and Summary of Significant Accounting Policies” and Note 9 “Derivative Instruments and Hedging Activities,” respectively, of our consolidated financial statements contained in Part II, Item 8 of this Annual Report

describe our commodity price risks and the instruments we use to manage them.

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

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

Discussion of Critical Accounting Policies

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

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

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

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

Independent reserve engineers prepare our oil and natural gas reserve estimates using guidelines established by the SEC and U.S. generally accepted accounting principles ("GAAP"). In December 2008, the SEC issued a final rule, "Modernization of Oil and Gas Reporting," which amended its oil and gas reserves estimation and disclosure requirements. The new requirements were codified into ASC 932 in January 2010 and had the effect of, among other things: permitting the use of new technologies to determine proved reserves if those technologies have been

demonstrated empirically to lead to reliable conclusions about reserve volumes; modifying the prices used to estimate reserves for SEC disclosure purposes to an unweighted, arithmetic average price based upon the prior twelve month period rather than the year-end price; and allowing the optional disclosure of “probable” and “possible” reserves to investors. The revised rule was effective January 1, 2010 for reporting December 31, 2009 annual oil and natural gas reserve information. We adopted the provisions of the final rule in connection with the preparation of our 2009 Annual Report. The quality and quantity of data, the interpretation of data, the accuracy of economic assumptions, and judgments and estimates regarding uncertain events and circumstances by us and our independent reserve engineers affect the accuracy of reserve estimates. We may materially revise our reserve estimates in subsequent periods due to drilling or production results or other data obtained after the date of the estimate.

As of December 31, 2012, we had estimated proved reserves of 77.4 Mmboe, of which 38% were proved developed producing reserves while 37% of our proved reserves were classified as proved developed non-producing reserves. Most of our proved developed non-producing reserves are classified as “behind pipe” and will be produced after depletion of another productive zone in the same well. Approximately 25% of total proved reserves are categorized as proved undeveloped reserves.

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

As of December 31, 2012, the computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves used an oil price based on the NYMEX WTI of $105.13 per barrel and a natural gas price based on the NYMEX Henry Hub of $2.92 per Mcf, computed by applying the use of physical pricing based on the unweighted, arithmetic average of the closing price on the first day of each of the twelve months during the fiscal year (as required by ASC 932), applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year-end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price. These adjustments can vary significantly over time both in amount and as a percentage of the posted price, especially related to our oil prices during periods when the market price for oil varies widely. The price adjustments reflected in our computed reserve prices may not represent the amount of price adjustments we may actually obtain in the future when we sell our production. We estimated the costs based primarily on our actual historical costs incurred for appropriate periods of time for individual properties. Where a particular property does not have production during the year, we apply pricing adjustments based on the most similar property.

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

In 2010, we had negative revisions of 4.3 Mmboe related to PUDs aged greater than five years for which funds were not committed in our 2011 development plan, representing 14% of our total proved reserves of 31.2 Mmboe as of December 31, 2009. Our past revisions have had minimal impact on our DD&A rates because they have been relatively low as a percentage of our reserve base and/or related to fields with little cumulative production. Historical revisions are not necessarily indicative of potential future revisions.

- Impairment of Oil and Natural Gas Properties—We evaluate our capitalized oil and natural gas property costs for potential impairment when circumstances indicate that the carrying value may not be recoverable. Because we accumulate capitalized costs separately, property by property (generally analogous to a field or a lease), for our proved oil and natural gas properties under the successful efforts method of accounting, we perform impairment assessments on a property by property basis. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve volumes, or other changes to contracts or environmental regulations. In general, we do not view temporarily low oil or natural gas prices

as a triggering event for conducting impairment tests. Historically, our sales price for oil and natural gas has varied significantly. Although our sales prices may rise and fall quickly over short periods of time, we believe sales prices over the long-term are primarily based on supply and demand factors. Accordingly, our impairment tests make use of long-term sales price assumptions for oil and natural gas. A significant amount of judgment and uncertainty is involved in performing impairment evaluations because major inputs to the computation are based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors.

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

property. Actual prices, costs, and net future cash flows may vary from our estimates. Our discount rate may not accurately reflect economic conditions. We recognized impairments of $8.9 million, $32.5 million and $26.1 million in the years ended December 31, 2012, 2011 and 2010, respectively.

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

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

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

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

• Share-Based Compensation—We measure compensation expense for all share-based payment awards based on their grant-date fair values. We use the Black-Scholes option pricing model to estimate fair values of share-based awards. Option pricing models, including the Black-Scholes model, require the use of input estimates and assumptions, including expected volatility, expected life, expected dividend rate, and expected risk-free rate of return. The assumptions for expected volatility and expected life most significantly affect the grant-date fair value. Our estimate of the forfeiture rate of our share-based awards also impacts the amount of expense recorded over the expected life of the award. See Note 12, "Employee Benefit Plans," in Part II, Item 8 of this Annual Report for a description of methods used to determine our assumptions. If we determined that another method used to estimate expected volatility or expected life was more reasonable than our current methods, or if another method for calculating these input assumptions was prescribed by authoritative guidance, the fair value calculated for share-based awards could change significantly. Higher volatility and longer expected lives result in increases to share-based compensation determined at the date of grant.

• Deferred Tax Asset Valuation Allowance—We are required to assess whether it is more likely than not that we will be able to realize some or all of our deferred tax assets. If we cannot determine that deferred tax assets are more likely

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

See Note 11 “Income Taxes” in Part II, Item 8 of this Annual Report for more information regarding our deferred taxes.

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

New Accounting Pronouncements

For information regarding new accounting pronouncements, see the information in Note 1 “Organization and Summary of Significant Accounting Policies—New Accounting Pronouncements” in the consolidated financial statements in Part II, Item 8 of this Annual Report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Interest Rate Risk

We are exposed to changes in interest rates which affect the interest earned on our interest-bearing deposits and the interest paid on borrowings under our Senior Credit Facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At December 31, 2012, we had $195.0 million drawn under our Senior Credit Facility and we had no amount outstanding at December 31, 2011. Borrowings under our Senior Credit Facility bear interest ranging from a base rate plus a margin of 0.75% to 1.75% on base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% on LIBOR borrowings. The maturity date of the Senior Credit Facility is October 31, 2016.

At December 31, 2012, our total indebtedness outstanding also includes $289.8 million (net of unamortized initial purchasers’ discount of $10.2 million) related to our fixed-rate 2012 Senior Notes and $205.1 million (net of unamortized initial purchasers’ discount of $4.9 million) related to our fixed-rate 2011 Senior Notes, which bear interest at an annual fixed rate of 8.25% and mature on February 15, 2018. At December 31, 2012, the estimated fair value of our 2012 Senior Notes and 2011 Senior Notes were approximately $309.9 million and $214.7 million, respectively.

Commodity Price Risk

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

Historically, we have used commodity derivative instruments to manage commodity price risks associated with future oil and natural gas production. The tables below provide information about our derivative instruments that were outstanding as of December 31, 2012. For a description of assumptions related to our calculations of fair value, please see Note 10, “Fair Value Measurements,” of the consolidated financial statements in Part II, Item 8 of this Annual Report.

Oil Contracts

	Fixed-Price Swaps			
	Daily Average Volume	Volume	Average Swap Price	Fair Value (In
Remaining Contract Term	(Bbls)	(Bbls)	($/Bbl)	thousands)
January 2013 - December 2013	9,993	3,647,300	$ 104.57	$ (3,946)
January 2014 - December 2014	7,736	2,823,500	101.06	(3,355)
January 2015 - December 2015	1,000	365,000	97.55	(164)

	Collars			
	Daily Average Volume	Volume	Strike Price	Fair Value (In
Remaining Contract Term	(Bbls)	(Bbls)	($/Bbl)	thousands)
January 2013—December 2013	1,000	365,000	$ 80.00/104.10	$ (2,769)

Gas Contracts

	Fixed-Price Swaps			
	Daily Average Volume	Volume	Average Swap Price	Fair Value (In
Remaining Contract Term	(Mmbtu)	(Mmbtu)	($/Mmbtu)	thousands)
January 2013 - December 2013	9,562	3,490,000	$ 3.51	$ (9)
January 2014 - December 2014	5,000	1,825,000	4.01	(34)
January 2015 - December 2015	4,300	1,569,500	4.31	127

During January and February 2013, we entered into the following derivative instruments:

Oil Contracts

	Daily Average	Average Swap
	Volume	Price
Contract Term	(Bbls)	($/Bbl)
July 2013	1,935	$ 107.90
January 2014 - December 2014	979	$ 102.09
January 2015 - December 2015	500	$ 98.00

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new regulation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, required the Commodities Futures Trading Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the new legislation. In July 2012 certain definitions were adopted by the SEC and the CFTC and based on those definitions, we believe we will qualify for the end-user exception related to the clearing requirement for swaps, but we are required to adhere to new reporting and recordkeeping requirements.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of EPL Oil & Gas, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows present fairly, in all material respects, the financial position of EPL Oil & Gas, Inc. and its subsidiaries (the "Company") at December 31, 2012 and December 31, 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/S/ PricewaterhouseCoopers LLP

New Orleans, Louisiana

March 7, 2013

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EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31, 2012 and 2011

(In thousands, except share data)

	December 31, 2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,521	$ 80,128
Trade accounts receivable - net	67,991	31,817
Fair value of commodity derivative instruments	3,302	587
Deferred tax asset	3,322	-
Prepaid expenses	9,873	11,046
Total current assets	86,009	123,578
Property and equipment, at cost under the successful efforts method of accounting	2,025,647	1,082,248
Less accumulated depreciation, depletion, amortization and impairments	(427,580)	(305,110)
Net property and equipment	1,598,067	777,138
Restricted cash	6,023	6,023
Fair value of commodity derivative instruments	211	-
Deferred financing costs - net of accumulated amortization of $2,596 and $1,061 at December 31, 2012 and 2011, respectively	12,386	5,452
Other assets	2,931	3,029
Total assets	$ 1,705,627	$ 915,220
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 34,772	$ 25,393
Accrued expenses	117,372	58,538
Asset retirement obligations	30,179	25,578
Fair value of commodity derivative instruments	10,026	1,056
Deferred tax liabilities	-	2,823
Total current liabilities	192,349	113,388
Long-term debt	689,911	204,390
Asset retirement obligations	204,931	73,769
Deferred tax liabilities	67,694	31,775
Fair value of commodity derivative instruments	3,637	190
Other	1,132	663
Total liabilities	1,159,654	424,175
Commitments and contingencies (Note 8)		
Stockholders' equity:		
Preferred stock, par value $0.001 per share. Authorized 1,000,000 shares; no shares issued and outstanding at December 31, 2012 and 2011	-	-
Common stock, par value $0.001 per share. Authorized 75,000,000 shares; shares issued: 40,601,887 and 40,326,451 at December 31, 2012 and 2011, respectively; shares		

outstanding: 39,103,203 and 39,404,106 at December 31, 2012 and 2011, respectively	40	40
Additional paid-in capital	510,469	505,235
Treasury stock, at cost, 1,498,684 and 922,345 shares at December 31, 2012 and 2011, respectively	(20,477)	(11,361)
Retained earnings (accumulated deficit)	55,941	(2,869)
Total stockholders’ equity	545,973	491,045
Total liabilities and stockholders' equity	$ 1,705,627	$ 915,220

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Years Ended December 31, 2012, 2011 and 2010

(In thousands, except per share data)

	Year Ended December 31,		
	2012	2011	2010
Revenue:			
Oil and natural gas	$ 422,529	$ 348,207	$ 239,770
Other	1,104	120	139
Total revenue	423,633	348,327	239,909
Costs and expenses:			
Lease operating	94,850	70,281	52,365
Transportation	615	779	1,306
Exploration expenditures and dry hole costs	18,799	14,268	6,441
Impairments	8,883	32,466	26,142
Depreciation, depletion and amortization	113,581	104,624	104,561
Accretion of liability for asset retirement obligations	15,565	15,942	12,845
General and administrative	23,208	18,741	18,078
Taxes, other than on earnings	13,007	14,365	10,133
Other	4,678	9,735	729
Total costs and expenses	293,186	281,201	232,600
Income from operations	130,447	67,126	7,309
Other income (expense):			
Interest income	136	102	113
Interest expense	(28,568)	(17,548)	(9,807)
Loss on derivative instruments	(13,305)	(5,870)	(4,865)
Loss on early extinguishment of debt	-	(2,377)	(5,627)
Total other expense	(41,737)	(25,693)	(20,186)
Income (loss) before income taxes	88,710	41,433	(12,877)
Deferred income tax benefit (expense)	(29,900)	(14,822)	4,409
Net income (loss)	58,810	26,611	(8,468)
Basic earnings (loss) per share	$ 1.50	$ 0.66	$ (0.21)
Diluted earnings (loss) per share	$ 1.50	$ 0.66	$ (0.21)
Weighted average common shares used in computing earnings (loss) per share:			
Basic	38,885	39,946	40,064
Diluted	39,034	40,050	40,064

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

For the Years Ended December 31, 2012, 2011 and 2010

(In thousands)

	Treasury Stock Shares	Treasury Stock	Common Stock Shares	Common Stock	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Total
Balance, December 31, 2009	-	$ -	40,022	$ 40	$ 501,059	$ (21,012)	$ 480,087
Net loss	-	-	-	-	-	(8,468)	(8,468)
Stock option and restricted share awards	-	-	69	-	1,429	-	1,429
Other	-	-	1	-	68	-	68
Balance, December 31, 2010	-	$ -	40,092	$ 40	$ 502,556	$ (29,480)	$ 473,116
Net income	-	-	-	-	-	26,611	26,611
Stock option and restricted share awards	6	(8)	217	-	2,509	-	2,501
Exercise of stock options	-	-	13	-	119	-	119
Purchase of shares into treasury	916	(11,353)	-	-	-	-	(11,353)
Other	-	-	4	-	51	-	51
Balance, December 31, 2011	922	$ (11,361)	40,326	$ 40	$ 505,235	$ (2,869)	$ 491,045
Net income	-	-	-	-	-	58,810	58,810
Stock option and restricted share awards	28	(318)	226	-	4,717	-	4,399
Exercise of stock options	-	-	48	-	441	-	441
Purchase of shares into treasury	549	(8,798)	-	-	-	-	(8,798)
Other	-	-	2	-	76	-	76
Balance, December 31, 2012	1,499	$ (20,477)	40,602	$ 40	$ 510,469	$ 55,941	$ 545,973

See accompanying notes to consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2012, 2011 and 2010

(In thousands)

	Year Ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ 58,810	$ 26,611	$ (8,468)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	113,581	104,624	104,561
Accretion of liability for asset retirement obligations	15,565	15,942	12,845
Unrealized loss (gain) on derivative instruments	9,491	(11,475)	(3,500)
Non-cash compensation	4,717	2,509	1,255
In-kind interest on PIK Notes	-	-	(3,395)
Deferred income taxes	29,900	14,822	(4,409)
Exploration expenditures	4,227	11,239	5,103
Impairments	8,883	32,466	26,142
Amortization of deferred financing costs and discount on debt	2,556	1,657	1,130
Loss on early extinguishment of debt	-	2,377	-
Other	2,448	6,984	(90)
Changes in operating assets and liabilities:			
Trade accounts receivable	(33,547)	(10,037)	6,515
Other receivables	-	2,088	3,376
Prepaid expenses	1,047	(7,623)	(363)
Other assets	145	(1,215)	618
Accounts payable and accrued expenses	31,477	12,650	2,361
Asset retirement obligation settlements	(35,429)	(32,364)	(16,130)
Other liabilities	-	(3)	(171)
Net cash provided by operating activities	213,871	171,252	127,380
Cash flows provided by (used in) investing activities:			
Decrease in restricted cash	-	2,466	13,658
Property acquisitions	(578,372)	(235,486)	(623)
Exploration and development expenditures	(184,850)	(76,003)	(58,183)
Other property and equipment additions	(1,743)	(1,568)	(755)
Net cash used in investing activities	(764,965)	(310,591)	(45,903)
Cash flows provided by (used in) financing activities:			
Proceeds from indebtedness	509,313	203,794	20,394
Repayments of indebtedness	(20,000)	-	(94,882)
Deferred financing costs	(8,469)	(6,646)	(181)

Purchase of shares into treasury	(8,798)	(11,353)	-
Exercise of stock options	441	119	-
Net cash provided by (used in) financing activities	472,487	185,914	(74,669)
Net increase (decrease) in cash and cash equivalents	(78,607)	46,575	6,808
Cash and cash equivalents at beginning of period	80,128	33,553	26,745
Cash and cash equivalents at end of period	$ 1,521	$ 80,128	$ 33,553

	Year Ended December 31,		
	2012	2011	2010
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Non-cash financing information:			
Debt incurred to pay deferred financing costs and surety bond premium	$ -	$ -	$ 737
Cash paid during the period for:			
Interest	21,129	9,395	8,307

See accompanying notes to consolidated financial statements.

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EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Summary of Significant Accounting Policies

EPL Oil & Gas, Inc. ("we," "our," "us," or "the Company") was incorporated as a Delaware corporation on January 29, 1998. We are 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. Effective September 1, 2012, we changed our legal corporate name from "Energy Partners, Ltd." to "EPL Oil & Gas, Inc." through a short-form merger pursuant to Section 253 of the General Corporation Law of the State of Delaware.

On October 31, 2012, we acquired from Hilcorp Energy GOM Holdings, LLC ("Hilcorp") 100% of the membership interests of Hilcorp Energy GOM, LLC ("Hilcorp Acquisition"), which owned certain shallow water Gulf of Mexico shelf oil and natural gas interests (the "Hilcorp Properties") for $550.0 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of $300.0 million in aggregate principal amount of 8.25% senior notes due 2018 (the "2012 Senior Notes") and borrowings under our expanded senior secured credit facility. Also on October 31, 2012, we obtained an increase in our senior credit facility from $250.0 million to $750.0 million. On May 15, 2012, we acquired an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests in our South Timbalier 41 field located in the Gulf of Mexico for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012 (the "ST41 Acquisition"). As a result of the ST41 Acquisition, we have become the sole working interest owner of the South Timbalier 41 field. We funded the ST41 Acquisition with cash on hand. See Note 2, "Acquisitions" for more information regarding these acquisitions and Note 7, "Indebtedness" for more information regarding the 2012 Senior Notes and our expanded credit facility.

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 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"). In connection with the ASOP Acquisition, on February 14, 2011, we issued $210.0 million in aggregate principal amount of 8.25% senior notes due 2018 (the "2011 Senior Notes") and we entered into our senior credit facility. On November 17, 2011, we acquired additional interests in the Main Pass 296/311 complex that was included in the ASOP Acquisition along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease for $38.6 million in cash, subject to customary adjustments to reflect an economic effective date of November 1, 2011 (the "Main Pass Acquisition"). See Note 2, "Acquisitions" for more information regarding these acquisitions and Note 7, "Indebtedness" for more information regarding the 2011 Senior Notes.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

(a) Basis of Presentation

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

(b) Property and Equipment

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

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

We evaluate our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicate that the carrying values may not be recoverable. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserve

volumes, or other changes to contracts, environmental regulations or tax laws. The calculation is performed on a field-by-field basis, utilizing our current estimates of future revenues and operating expenses. In the event net undiscounted cash flow is less than the carrying value, an impairment loss is recorded based on the present value of expected future net cash flows over the economic lives of the reserves.

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

(c) Asset Retirement Obligations

We record our obligations associated with the retirement of tangible long-lived assets at their fair values in the period incurred. The fair value of the obligation is also recorded to the related asset's carrying amount. Accretion of the liability is recognized as an operating expense and the capitalized cost is amortized using the units-of-production method. We revise our estimates of asset retirement obligations as information about material changes to the liability becomes known. Revisions are recorded as adjustments to existing liabilities and to the carrying amount of the related assets. Revisions occurring at or near the end of an asset's useful life may materially impact earnings. Our asset retirement obligations relate primarily to the plugging and abandonment of our oil and natural gas wellbores and to decommissioning related pipelines, facilities and structures.

(d) Income Taxes

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

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

(e) Deferred Financing Costs

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

(f) Earnings Per Share

Basic earnings per share is computed by dividing income or loss available to common stockholders by the weighted average number of common shares outstanding during each period. According to GAAP, we have determined that our unvested restricted share awards, which contain non-forfeitable rights to dividends, are participating securities and should be included in the computation of earnings per share pursuant to the "two-class" method. The "two-class" method allocates undistributed earnings between common shares and participating securities. The diluted earnings per share calculation under the "two-class" method also includes the effect, if dilutive, of potential common shares associated with stock option awards outstanding during each period. The dilutive effect of stock options is determined using the treasury stock method.

(g) Revenue Recognition

We record revenues from the sales of oil and natural gas when the product is delivered at a determinable price, title has transferred and collectability is reasonably assured. When we have an interest with other producers in properties from which natural gas is produced, we use the entitlement method for recording natural gas sales revenue. Under this method of accounting, revenue is recorded based on our net revenue interest in production. Deliveries of natural gas in excess of our revenue interest are recorded as liabilities and under-deliveries are recorded as receivables. We had natural gas imbalance liabilities of $1.7 million and $1.6 million at December 31, 2012 and 2011, respectively. We had natural gas imbalance receivables of $0.8 million and $1.0 million at December 31, 2012 and 2011, respectively.

(h) Cash and Cash Equivalents

We include in cash and cash equivalents our highly-liquid investments with original maturities of three months or less. At December 31, 2012 and 2011, cash and cash equivalents includes investments in overnight interest-bearing deposits of $2.3 million and $51.8 million, respectively. These amounts are reduced by overdraft balances on other operating accounts

with legal right of offset in the same banking institution to arrive at the cash and cash equivalent balances reported in our consolidated balance sheets.

(i) Derivative Activities

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

(j) Share-Based Compensation

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

We are required to report excess tax benefits from the exercise of stock options as financing cash flows. For the year ended December 31, 2012 and 2011, no excess tax benefits were reported in the statement of cash flows as we were in a net operating loss carryforward position. No stock options were exercised during 2010. See Note 12 for additional disclosures.

(k) Allowance for Doubtful Accounts

We routinely assess the recoverability of all material trade and other receivables to determine their collectability. Our crude oil and natural gas revenue receivables are typically collected within two months. We may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest receivables on properties where we are the operator. When we believe collection of the full amount of our accounts receivable is in doubt, we record an allowance to reflect accounts receivable at the net realizable value, which may be reflected in earnings or as an increase to the net book value of our oil and natural gas properties depending on the nature of the transaction that created the receivable. The nature of the transaction resulting in the receivable balance determines whether the allowance, when recorded, impacts our earnings (ordinarily through LOE) or our property and equipment balances. As of December 31, 2012, our allowance for doubtful accounts was $0.7 million, $0.1 million of which was recorded as a recovery in earnings in 2012. As of December 31, 2011, our allowance for doubtful accounts was $1.7 million, $0.5 million of which was recorded as a recovery in earnings in 2011.

(l) Accrued Expenses

As of December 31, 2012, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $84.9 million, other accrued expenses of $16.3 million and interest payable of approximately $16.2 million. As of December 31, 2011, our accrued expenses included accrued exploration costs, development costs and lease operating expenses totaling approximately $39.5 million, other accrued expenses of $12.5 million and interest payable of approximately $6.5 million.

(m) Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those

estimates. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We use historical experience and various other assumptions that are believed to be reasonable under the circumstances to form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. Our actual results may differ from these estimates and assumptions used in preparation of our financial statements. Significant estimates with regard to these financial statements and related unaudited disclosures include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows therefrom disclosed in Note 15.

(n) New Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (the “FASB”) issued Accounting Standards Update (“ASU”) No. 2011-11, “Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities” (“ASU 2011-11”). ASU 2011-11 requires disclosure of information about offsetting and related arrangements to enable users of financial statements to understand the effect or potential effect of netting arrangements on an entity’s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. In January 2013, the FASB issued ASU No. 2013-01, “Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about

Offsetting Assets and Liabilities," to clarify that ASU 2011-11 applies to derivatives, repurchase agreements and securities lending transactions. The required disclosures are effective for our annual report for the year ending December 31, 2013 and for interim periods within that year. We have not yet completed our review of the required disclosures; however, we expect to enhance our disclosures related to our derivative instruments in accordance with the requirements of ASU 2011-11.

(2) Acquisitions and Dispositions

The Hilcorp Acquisition

On October 31, 2012, we acquired the Hilcorp Properties for $550.0 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. As of December 31, 2012, the Hilcorp Properties had estimated proved reserves of approximately 37.2 Mmboe, of which 49% were oil and 58% were proved developed reserves. The primary factors considered by management in acquiring the Hilcorp Properties include the belief that the Hilcorp 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 on the Gulf of Mexico shelf. The Hilcorp Acquisition also provides us with access to infrastructure and extensive acreage, with significant exploitation and development potential.

The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of the 2012 Senior Notes and borrowings under our expanded senior credit facility. The 2012 Senior Notes were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the Securities Act of 1933, as amended (the "Securities Act"), or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. After deducting the initial purchasers' discount, we realized net proceeds of $289.5 million. See Note 7, "Indebtedness," for more information regarding our 2012 Senior Notes.

The following allocation of the purchase price is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these consolidated financial statements were prepared and takes into account current market conditions and estimated market prices for oil and natural gas. Management has not yet had the opportunity to complete its assessment of fair values of the assets acquired and liabilities assumed. In addition, the purchase price could change materially as management finalizes adjustments to purchase price provided for by the purchase and sale agreement. Accordingly, the allocation may change materially as additional information becomes available and is assessed by management.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects management's estimate of customary adjustments to purchase price provided for by the purchase and sale agreement of approximately $7.5 million to reflect an economic effective date of July 1, 2012.

(In thousands)	July 1, 2012
Oil and natural gas properties	$ 671,310
Asset retirement obligations	(128,817)
Net assets acquired	$ 542,493

The South Timbalier Acquisition

On May 15, 2012, we acquired from W&T Offshore, Inc. ("W&T") an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests in our South Timbalier 41 field (the "ST41 Interests") located in the

Gulf of Mexico for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012. We estimate that the proved reserves as of the April 1, 2012 economic effective date totaled approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. Prior to the ST41 Acquisition, we owned a 60% working interest in these properties, and W&T owned a 40% working interest. As a result of the ST41 Acquisition, we have become the sole working interest owner of the South Timbalier 41 field. We funded the ST41 Acquisition with cash on hand.

The following allocation of the purchase price as of April 1, 2012 is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these consolidated financial statements were prepared and is subject to revision as management finalizes adjustments to purchase price provided for by the purchase and sale agreement. Accordingly, the allocation may change materially as additional information becomes available and is assessed by management.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects adjustments to purchase price provided for by the purchase and sale agreement of approximately $0.7 million to reflect an economic effective date of April 1, 2012.

(In thousands)	April 1, 2012
Oil and natural gas properties	$ 33,587
Asset retirement obligations	(1,878)
Net assets acquired	$ 31,709

The ASOP Acquisition

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 ASOP for $200.7 million in cash, subject to purchase price adjustments to reflect an economic effective date of January 1, 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. The primary factors considered by management in acquiring the ASOP Properties include the belief that the ASOP Acquisition provided 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. We financed the ASOP Acquisition with the proceeds from the sale of $210.0 million in aggregate principal amount of the 2011 Senior Notes. After deducting the initial purchasers' discount and offering expenses, we realized net proceeds of approximately $202.0 million. See Note 7, "Indebtedness" for more information regarding our 2011 Senior Notes.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects adjustments to purchase price provided for by the purchase and sale agreement of approximately $3.8 million to reflect an economic effective date of January 1, 2011.

(In thousands)	January 1, 2011
Oil and natural gas properties	$ 221,751
Asset retirement obligations	(24,858)
Net assets acquired	$ 196,893

The Main Pass Acquisition

On November 17, 2011, we acquired certain interests in producing oil and natural gas assets in the shallow-water central Gulf of Mexico shelf (the "Main Pass Interests") from Stone Energy Offshore, L.L.C. (the "Seller") for $38.6 million in cash, subject to customary adjustments to reflect the economic effective date of November 1, 2011. The Main Pass Interests consist of additional interests in the Main Pass 296/311 complex that was included in the ASOP Acquisition, along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease. We estimate that the proved reserves as of the November 1, 2011 economic effective date totaled approximately 1.3 Mmboe, all of which were proved developed reserves and 96% of which were oil reserves. We funded the Main Pass Acquisition with cash on hand.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects adjustments to purchase price provided for by the purchase and sale agreement of approximately $0.7 million to reflect an economic effective date of November 1, 2011.

(In thousands)	November 1, 2011
Oil and natural gas properties	$ 40,826
Asset retirement obligations	(2,991)
Net assets acquired	$ 37,835

We have accounted for our acquisitions using the purchase method of accounting for business combinations, and therefore we have estimated the fair value of the assets acquired and the liabilities assumed as of their respective acquisition dates. In the estimation of fair value, management uses various valuation methods including (i) comparable company analysis, which estimates the value of the acquired properties based on the implied valuations of other similar operations; (ii) comparable asset transaction analysis, which estimates the value of the acquired operations based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of operations based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis. The fair value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties which are beyond our control. These assumptions represent Level 3 inputs, as further discussed in Note 10, “Fair Value Measurements.”

Results of Operations and Pro Forma Information

Revenues and lease operating expenses attributable to the Hilcorp Properties, the ST41 Interests, the ASOP Properties and the Main Pass Interests were as follows:

	Year Ended December 31,	
	2012	2011
	(In thousands)	
Hilcorp Properties:		
Revenues	$ 37,978	$ -
Lease operating expenses	$ 6,711	$ -
ST41 Interests:		
Revenues	$ 9,262	$ -
Lease operating expenses	$ 1,760	$ -
ASOP Properties and Main Pass Interests:		
Revenues	$ 175,538	$ 125,975
Lease operating expenses	$ 26,467	$ 17,161

We have determined that the presentation of net income attributable to the Hilcorp Properties, the ST41 Interests, the ASOP Properties and the Main Pass Interests is impracticable due to the integration of the related operations upon acquisition. We incurred fees of approximately $0.5 million related to the Hilcorp Acquisition and approximately $0.1 million related to the ST41 Acquisition, which were included in general and administrative expenses in the accompanying consolidated statement of operations for the year ended December 31, 2012. We incurred fees of approximately $0.5 million related to the ASOP Acquisition and approximately $0.1 million related to the Main Pass Acquisition, which were included in general and administrative expenses in the accompanying consolidated statement of operations for the year ended December 31, 2011.

The following supplemental pro forma information presents consolidated results of operations as if the Hilcorp Acquisition, the ST41 Acquisition, the ASOP Acquisition and the Main Pass Acquisition had occurred on January 1, 2011. The supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations, b) the statements of operations of Hilcorp Energy GOM, LLC, c) the statements of revenues and direct operating expenses for the ST41 Interests, which were derived from our historical accounting records, d) the statements of revenues and direct operating expenses for the ASOP Properties, which were derived from ASOP’s

historical accounting records and e) the statements of revenues and direct operating expenses for the Main Pass Interests, which were derived from the historical accounting records of the Seller. This information does not purport to be indicative of results of operations that would have occurred had the acquisitions occurred on January 1, 2011, nor is such information indicative of any expected future results of operations.

	Year Ended December 31,	
	Pro Forma 2012	Pro Forma 2011
	(in thousands, except per share data)	
Revenue	$ 594,510	$ 661,194
Net income	$ 53,725	$ 27,630
Basic earnings per share	$ 1.37	$ 0.69
Diluted earnings per share	$ 1.37	$ 0.69

Subsequent Events

On March 5, 2013 we executed a purchase and sale agreement to sell certain shallow water Gulf of Mexico shelf oil and natural gas interests located within the non-operated Bay Marchand field area (the "BM Interests") to the property operator for $51.5 million in cash and the buyer's assumption of liabilities recorded on our balance sheet of $10.8 million resulting in total consideration of $62.3 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. We expect to close the transaction by April 1, 2013. As of December 31, 2012, the net book value of the BM Interests was approximately $35.6 million.

(3) Common Stock

In August 2011, the Board of Directors authorized a program for the repurchase of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million. In May 2012, the Board of Directors authorized an increase to the program from $20.0 million to $40.0 million. The repurchases have been, and will be, carried out in accordance with certain volume, timing and price constraints imposed by the Securities and Exchange Commission (the "SEC") rules applicable to such transactions. The amount, timing and price of purchases otherwise depend on market conditions and other factors. Through December 31, 2012, we executed trades to repurchase 1,465,300 shares at an aggregate cash purchase price of approximately $20.1 million. The repurchased shares are held in treasury and could be used to provide available shares for possible resale in future public or private offerings and our employee benefit plans.

We have reserved up to 2,474,000 shares of common stock for the issuance of restricted shares and option shares under our 2009 Long-Term Incentive Plan, with 679,608 shares remaining for issuance as of December 31, 2012. In May 2011, the reserved shares were increased from 1,237,000 shares to 2,474,000. See Note 12, "Employee Benefit Plans" for information regarding the 2009 Long-Term Incentive Plan.

Covenants in certain debt instruments to which we are a party, including our credit facility and the indentures related to our 2012 Senior Notes and 2011 Senior Notes, place certain restrictions and conditions on our ability to pay dividends on our common stock.

(4) Earnings Per Share

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods.

Year Ended December 31,

	2012	2011	2010
	(in thousands, except per share data)		
Income (numerator):			
Net income (loss)	$ 58,810	$ 26,611	$ (8,468)
Net income attributable to participating securities	(455)	(77)	-
Net income (loss) attributable to common shares	$ 58,355	$ 26,534	$ (8,468)
Weighted average shares (denominator):			
Weighted average shares—basic	38,885	39,946	40,064
Dilutive effect of stock options	149	104	-
Weighted average shares—diluted	39,034	40,050	40,064
Basic earnings (loss) per share	$ 1.50	$ 0.66	$ (0.21)
Diluted earnings (loss) per share	$ 1.50	$ 0.66	$ (0.21)

The following table indicates the number of shares underlying outstanding stock-based awards excluded from the computation of dilutive weighted average shares because their effect was antidilutive for the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Weighted average shares	687	442	409

For the year ended December 31, 2010, all outstanding stock options and unvested restricted shares were considered antidilutive because we had a net loss for the period.

(5) Property and Equipment

The following table summarizes our property and equipment.

	December 31,	
	2012	2011
	(In thousands)	
Proved oil and natural gas properties	$ 1,982,657	$ 1,049,140
Unproved oil and natural gas properties	36,992	29,382
Other	5,998	3,726
Total property and equipment	$ 2,025,647	$ 1,082,248

Substantially all of our oil and natural gas properties serve as collateral under our credit facility.

We recognized impairments of $8.9 million, $32.5 million and $26.1 million in the years ended December 31, 2012, 2011 and 2010, respectively.

Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices affecting certain of our natural gas producing fields and to reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that are expiring in 2013 for which we have no development plans.

Impairments for the year ended December 31, 2011 were primarily related to our natural gas producing fields and our deepwater producing well (primarily natural gas). Impairments related to our deepwater producing well were primarily due to the decline in our estimate of future natural gas prices, reservoir performance and higher estimated operating costs. Additional impairments for the year ended December 31, 2011 were primarily related to reservoir performance at other natural gas producing fields.

Impairments for the year ended December 31, 2010 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2010 as compared to June 30, 2010 affecting two producing fields, including our deepwater producing well, and to reservoir performance of one of these fields and one additional producing field. These producing fields were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values during the year ended December 31, 2010.

At December 31, 2012 and 2011, we did not have any exploratory projects that were suspended for a period greater than one year.

(6) Asset Retirement Obligations

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

	Year Ended December 31,	
	2012	2011
	(in thousands)	
Beginning of period total	$ 99,347	$ 71,583
Accretion expense	15,565	15,942
Liabilities assumed in acquisitions	132,109	26,435
Liabilities incurred	1,210	157
Revisions	22,308	17,595
Liabilities settled	(35,429)	(32,365)
End of period total	235,110	99,347
Less: End of period, current portion	(30,179)	(25,578)
End of period, noncurrent portion	$ 204,931	$ 73,769

As of December 31, 2011, we increased our cost estimates on a portion of our asset retirement obligations to reflect higher overall prices for services, material and equipment. Primarily due to changes in estimated reserve lives, the timing of a

portion of our asset retirement obligations was revised in the fourth quarter of 2011 leading to a reduction of the present value of those obligations, partially offsetting the impact of the cost increases.

(7) Indebtedness

The following table sets forth our indebtedness.

	December 31,	
	2012	2011
	(In thousands)	
8.25% senior notes issued February 14, 2011, face amount of $210.0 million, interest rate of 8.25% payable semi- annually, in arrears on February 15 and August 15 of each year, maturity date February 15, 2018	$ 205,125	$ 204,390
8.25% senior notes issued October 25, 2012, face amount of $300.0 million, interest rate of 8.25% payable semi-annually, in arrears on February 15 and August 15 of each year, maturity date February 15, 2018	289,786	-
Senior credit facility, interest rate based on base rate or LIBOR plus a floating spread, maturity date October 31, 2016	195,000	-
Total indebtedness	689,911	204,390
Current portion of indebtedness	-	-
Noncurrent portion of indebtedness	$ 689,911	$ 204,390

On October 25, 2012, we issued the $300.0 million in aggregate principal amount of our 2012 Senior Notes. On October 31, 2012, we obtained an increase in our senior credit facility from $250.0 million to $750.0 million. The net proceeds from the sale of our 2012 Senior Notes and borrowings under our senior credit facility were used to fund the Hilcorp Acquisition (see Note 2).

On February 14, 2011, in connection with the ASOP Acquisition (see Note 2), we issued the $210.0 million in aggregate principal amount of our 2011 Senior Notes. Furthermore, our credit facility existing on that date was terminated and replaced with our senior credit facility. The termination of our prior credit facility during the year ended December 31, 2011 resulted in a loss on early extinguishment of debt of $2.4 million, primarily due to writing off the unamortized deferred financing costs associated with the terminated facility.

2012 Senior Notes

On October 25, 2012, we issued the $300.0 million in aggregate principal amount of our 2012 Senior Notes under an Indenture dated as of October 25, 2012 (the “2012 Indenture”). As described in Note 2, “Acquisitions,” we used the net proceeds from the offering of the 2012 Senior Notes of $289.5 million, after deducting the initial purchasers’ discount, to fund a portion of the Hilcorp Acquisition. The 2012 Senior Notes bear interest from August 15, 2012 at an annual rate of 8.25% with interest due semi-annually, in arrears on February 15th and August 15th of each year commencing on February 15, 2013. The purchase price of the 2012 Senior Notes included $4.8 million of accrued interest for the period from August 15, 2012 to October 25, 2012, which we recorded as interest payable. The 2012 Senior Notes are fully and unconditionally guaranteed on a senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 2012 Senior Notes mature on February 15, 2018. The effective interest rate on the 2012 Senior Notes is approximately 9.2%.

The 2012 Senior Notes were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the the Securities Act, or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. The 2012 Senior Notes have terms that are substantially identical to the terms of our 2011 Senior Notes, other than with respect to special mandatory redemption provisions related to the closing of the Hilcorp Acquisition. Such provisions are now inapplicable because the Hilcorp Acquisition has closed. However, the 2012 Senior Notes were issued under a different indenture as a separate class of securities and therefore, until exchanged for an issue of additional notes to be publicly registered (the "Exchange Notes"), will not trade together with the 2011 Senior Notes. Pursuant to a registration rights agreement executed as part of the sale of the 2012 Senior Notes (the "Registration Rights Agreement"), we have agreed to issue publicly registered additional notes under our Indenture, dated as of February 14, 2011 (the "2011 Indenture"), in exchange for the 2012 Senior Notes.

Under the Registration Rights Agreement, we and our guarantor subsidiaries (the "Guarantors") agreed to file a registration statement with the SEC offering to exchange the 2012 Senior Notes for the Exchange Notes under the 2011 Indenture which notes have terms substantially identical to the 2012 Senior Notes (except that the Exchange Notes will not be subject to restrictions on transfer or contain terms with respect to the payment of liquidation damages). We and the Guarantors have agreed to (i) file a registration statement for the Exchange Notes with the SEC on or prior to March 24,

2013, which is the date that is 150 days after the October 25, 2012 closing of the 2012 Senior Notes offering; (ii) use commercially reasonable efforts to cause the registration statement to be declared effective as soon as practicable, but in any event on or prior to May 23, 2013, which is the date that is 210 days after the October 25, 2012 closing of the 2012 Senior Notes offering; and (iii) use commercially reasonable efforts to close the exchange offer on or prior to 30 business days after the registration statement is declared effective. In certain circumstances, we may be required to file a shelf registration statement to cover resales of the notes. The use of the shelf registration statement will be subject to certain customary suspension periods. If we and the Guarantors do not meet these deadlines, we will be required to pay special interest to holders of notes under certain circumstances.

2011 Senior Notes

On February 14, 2011, we issued the $210.0 million in aggregate principal amount of our 2011 Senior Notes under the 2011 Indenture, dated as of February 14, 2011. As described in Note 2, “Acquisitions,” we used the net proceeds from the offering of the 2011 Senior Notes of $202.0 million, after deducting the initial purchasers’ discount and offering expenses payable by us, to acquire the ASOP Properties for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011, and for general corporate purposes. The 2011 Senior Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due semi-annually, in arrears, on February 15th and August 15th of each year, commencing on August 15, 2011. The 2011 Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 2011 Senior Notes will mature on February 15, 2018. The effective interest rate on the 2011 Senior Notes is approximately 9.0%.

The 2011 Senior Notes were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the Securities Act, or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. In connection with the execution of the Original Indenture, we also entered into a registration rights agreement, dated as of February 14, 2011. Under this agreement, on July 14, 2011, we and our guarantor subsidiaries filed a registration statement with the SEC, which was declared effective on July 26, 2011, offering to exchange a new series of freely tradable notes having substantially identical terms as the 2011 Senior Notes (“Original Exchange Notes”) for the 2011 Senior Notes. Pursuant to this offering, 100% in aggregate principal amount of the 2011 Senior Notes was exchanged for the 2011 Exchange Notes, effective as of August 29, 2011.

On or after February 15, 2015, we may on any one or more occasions redeem all or a part of the 2012 Senior Notes and 2011 Senior Notes (collectively, the “8.25% Notes) upon not less than 30 nor more than 60 days’ notice, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest and special interest, if any, on the notes redeemed, to the applicable date, if redeemed during the twelve-month period beginning on February 15 of the years indicated below, subject to the rights of holders of notes on the relevant record date to receive interest on the relevant interest payment date:

Year	Percentage
2015	104.125%
2016	102.063%
2017 and thereafter	100.000%

Any such redemption and notice may, in our discretion, be subject to the satisfaction of one or more conditions, precedent, including, but not limited to, the occurrence of a change of control. Unless we default in the payment of the redemption price, interest will cease to accrue on the 8.25% Notes or portions thereof called for redemption on the applicable redemption date.

At any time prior to February 15, 2014, we may, at our option, on any one or more occasions redeem with the net cash proceeds of certain equity offerings up to 35% of the aggregate principal amount of outstanding 8.25% Notes (which amount includes additional notes issued under the 2011 Indenture and the 2012 Indenture (together, the "Indentures"), upon not less than 30 nor more than 60 days' notice, at a redemption price equal to 108.25% of the principal amount of the notes redeemed, plus the accrued and unpaid interest and special interest, if any, to the redemption date, provided that: (1) at least 65% of the aggregate principal amount of notes issued under the Indentures (which amount includes additional notes under the Indentures) remains outstanding immediately after the occurrence of such redemption; and (2) the redemption occurs within 90 days of the date after the closing of such equity offering. This option to redeem up to 35% of the aggregate principal amount of outstanding 8.25% Notes with the net cash proceeds of certain equity offerings is considered an embedded derivative. We estimate that the fair value of this option at December 31, 2012 is not material. In addition, we may, at our option, on any one or more occasions redeem all or a part of the 8.25% Notes prior to February 15, 2015 at a redemption price equal to 100% of the principal amount of the 8.25% Notes redeemed plus a "make-whole" premium as of, and accrued and unpaid interest to the redemption date.

If we experience a change of control (as defined in the Indentures), each holder of the 8.25% Notes will have the right

to require us to repurchase all or any part (equal to $2,000 or an integral multiple of $1,000 in excess thereof) of the 8.25% Notes at a price in cash equal to 101% of the aggregate principal amount of the 8.25% Notes repurchased, plus accrued and unpaid interest to the date of repurchase. If we engage in certain asset sales, within 360 days of such sale, we generally must use the net cash proceeds from such sales to repay outstanding senior secured debt (other than intercompany debt or any debt owed to an affiliate), to acquire all or substantially all of the assets, properties or capital stock of one or more companies in our industry, to make capital expenditures or to invest in our business. When any such net proceeds that are not so applied or invested exceed $20.0 million, we must make an offer to purchase the 8.25% Notes and other pari passu debt that is subject to similar asset sale provisions in an aggregate principal amount equal to the excess net cash proceeds. The purchase price of each 8.25% Note (or other pari passu debt) so purchased will be 100% of its principal amount, plus accrued and unpaid interest to the repurchase date, and will be payable in cash.

The Indentures, among other things, limit our ability to: (i) declare or pay dividends, redeem subordinated debt or make other restricted payments; (ii) incur or guarantee additional debt or issue preferred stock; (iii) create or incur liens; (iv) incur dividend or other payment restrictions affecting restricted subsidiaries; (v) consummate a merger, consolidation or sale of all or substantially all of our assets; (vi) enter into sale-leaseback transactions, (vii) enter into transactions with affiliates; (viii) transfer or sell assets; (ix) engage in business other than our current business and reasonably related extensions thereof; or (x) issue or sell capital stock of certain subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the Indentures.

Senior Credit Facility

On February 14, 2011, we entered into our senior secured credit facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto (as amended and restated, the “Senior Credit Facility”). The original terms of our Senior Credit Facility established a revolving credit facility with a four-year term that could be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million. On October 31, 2012, in connection with the Hilcorp Acquisition, through an amendment and restatement of our Senior Credit Facility, the aggregate commitment under this facility was increased to a maximum of $750.0 million and the maturity date was extended to October 31, 2016. The maximum amount of letters of credit that may be outstanding at any one time is $20.0 million. The amount available under the revolving credit facility is limited by the borrowing base. The borrowing base under our Senior Credit Facility has been determined at the discretion of the lenders, based on the collateral value of our proved reserves and is subject to potential special and regular semi-annual redeterminations. On October 31, 2012, the borrowing base under the expanded credit facility was increased from $200.0 million to $425.0 million. On October 31, 2012, we borrowed $205.0 million under the Senior Credit Facility to fund a portion of the purchase price and related expenses of the Hilcorp Acquisition. As of December 31, 2012, we had $195.0 million drawn under our Senior Credit Facility, and the borrowing base remains at $425.0 million. We had no amounts drawn under our Senior Credit Facility at December 31, 2011.

The interest rate spread on loans and letters of credit under our Senior Credit Facility is based on the level of utilization and range from a base rate plus a margin of 0.75% to 1.75% for base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% for LIBOR borrowings. Commitment fees ranging from 0.375% to 0.50% are payable on the unused portion of the borrowing base. Interest on our base rate borrowings is payable quarterly, in arrears, and interest on our LIBOR borrowings is payable on the last day of each relevant interest period, except that in the case of any interest period that is longer than three months, interest is payable on each successive date three months after the first day of such interest period.

Our Senior Credit Facility contains customary covenants, default provisions and collateral requirements. As described in the agreement underlying our Senior Credit Facility, we must maintain, for each period for which a covenant certification is required, (a) a minimum current ratio (as defined in the agreement for our Senior Credit Facility) of 1.0 to 1.0 and (b) a maximum total debt to EBITDAX ratio of 3.5 to 1.0. We are also required to maintain a commodities

hedging program that is in compliance with the requirements set forth in our Senior Credit Facility. Our Senior Credit Facility also places restrictions on the maximum estimated future production volumes that can be subject to commodity derivative instruments.

Our obligations under our Senior Credit Facility, as well as any hedging contracts and treasury management agreements with the lenders or affiliates of lenders, are secured by substantially all of our assets, including a) mortgages on at least 80% of the total value of our oil and gas properties evaluated in the most recently completed reserve report, after giving effect to exploration and production activities, acquisitions and dispositions, and b) the stock of certain wholly-owned subsidiaries.

(8) Concentrations

Significant Customers

We had oil and natural gas sales to three customers accounting for 45%, 31% and 11%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2012.We had oil and natural gas sales to three customers accounting for 51%, 17% and 12%, respectively, of total oil and natural gas revenues,

excluding the effects of hedging activities, for the year ended December 31, 2011. We had oil and natural gas sales to three customers accounting for 42%, 26% and 11%, respectively, of total oil and natural gas revenues, excluding the effects of hedging activities, for the year ended December 31, 2010.

Geographic Concentration

Virtually all of our current operations and proved reserves are concentrated in the Gulf of Mexico region. Therefore, we are exposed to operational, regulatory and other risks associated with the Gulf of Mexico, including the risk of adverse weather conditions. We maintain insurance coverage against some, but not all, of the operating risks to which our business is exposed.

(9) Derivative Instruments and Hedging Activities

We enter into derivative instruments to reduce exposure to fluctuations in the price of oil and natural gas for a portion of our production. Our fixed-price swaps fix the sales price for a limited amount of our production and, for the contracted volumes, eliminate our ability to benefit from increases in the sales price of the production. Our collars limit our exposure to declines in the sales price of oil while giving us the ability to benefit from increases in the sales price of oil to a certain level for a limited amount of our production. Derivative instruments are carried at their fair value on the consolidated balance sheets as Fair value of commodity derivative instruments and all unrealized and realized gains and losses are recorded in Gain (loss) on derivative instruments in Other income (expense) in the consolidated statements of operations. See Note 10 for information regarding fair values of our derivative instruments.

The following tables set forth our derivative instruments outstanding as of December 31, 2012.

Oil Contracts

	Fixed-Price Swaps		
Remaining Contract Term	Daily Average Volume (Bbls)	Volume (Bbls)	Average Swap Price ($/Bbl)
January 2013	13,292	412,050	$ 105.33
February 2013	13,264	371,400	105.18
March 2013	12,792	396,550	104.88
April 2013	12,783	383,500	104.73
May 2013	12,727	394,550	104.63
June 2013	12,217	366,500	104.41
July 2013	9,510	294,800	104.25
August 2013	6,219	192,800	104.70
September 2013	6,233	187,000	104.44
October 2013	5,719	177,300	103.94
November 2013	6,233	187,000	103.93
December 2013	9,156	283,850	103.24
2013 Total	9,993	3,647,300	104.57

January 2014	10,500	325,500	100.99
February 2014	10,500	294,000	100.99
March 2014	10,500	325,500	100.99
April 2014	8,500	255,000	101.08
May 2014	8,500	263,500	101.08
June 2014	8,500	255,000	101.08
July 2014	8,500	263,500	101.08
August 2014	5,500	170,500	100.94
September 2014	5,500	165,000	100.94
October 2014	5,500	170,500	100.94
November 2014	5,500	165,000	100.94
December 2014	5,500	170,500	100.94
2014 Total	7,736	2,823,500	101.06
January 2015 - December 2015	1,000	365,000	97.55

	Collars		
	Daily Average Volume	Volume	Average Swap Price
Remaining Contract Term	(Bbls)	(Bbls)	($/Bbl)
January 2013—December 2013	1,000	365,000	$ 80.00/104.10
Gas Contracts			

	Fixed-Price Swaps		
	Daily Average Volume	Volume	Average Swap Price
Remaining Contract Term	(Mmbtu)	(Mmbtu)	($/Mmbtu)
January 2013	13,000	403,000	$ 3.41
February 2013	13,000	364,000	3.43
March 2013	11,000	341,000	3.42
April 2013	11,000	330,000	3.42
May 2013	10,000	310,000	3.46
June 2013	9,000	270,000	3.50
July 2013	9,000	279,000	3.53
August 2013	8,500	263,500	3.55
September 2013	8,500	255,000	3.55
October 2013	8,000	248,000	3.58
November 2013	7,500	225,000	3.67
December 2013	6,500	201,500	3.83
2013 Total	9,562	3,490,000	3.51
January 2014 - December 2014	5,000	1,825,000	4.01
January 2015 - December 2015	4,300	1,569,500	4.31

The following table presents information about the components of loss on derivative instruments.

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Unrealized gain (loss) due to change in fair market value	$ (9,491)	$ 11,475	$ 3,500
Realized loss on settlement	(3,814)	(17,345)	(8,365)
Total loss on derivative instruments	$ (13,305)	$ (5,870)	$ (4,865)

(10) Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. ASC Topic 820, “Fair Value Measurements and Disclosures,” establishes a fair value hierarchy with three levels based on the reliability of the inputs used to determine fair value. These levels include: Level 1, defined as inputs such as unadjusted quoted prices in active markets for identical assets and liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions. In May 2011, the FASB issued ASU No. 2011-04, “Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs” (“ASU 2011-04”), which became effective for us in the quarter ended March 31, 2012. ASU 2011-04 includes additional guidance related to fair value measurement principles and additional disclosure requirements. The impact of adopting ASU 2011-04 was immaterial.

As of December 31, 2012 and 2011, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, primarily our commodity derivative instruments. The fair values of derivative instruments were measured using price inputs published by NYMEX and IntercontinentalExchange, Inc., or ICE. These price inputs are quoted prices for assets and liabilities similar to those held by us and meet the definition of Level 2 inputs within the fair

value hierarchy. The following table sets forth our financial assets and liabilities that are accounted for at fair value on a recurring basis.

	December 31,	
	2012	2011
	(in thousands)	
Assets:		
Fair value of commodity derivative instruments	$ 3,513	$ 587
Liabilities:		
Fair value of commodity derivative instruments	$ 13,663	$ 1,246

The carrying values reported in the consolidated balance sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short term maturities of these instruments. The fair values for the 2011 Senior Notes and 2012 Senior Notes are based on quoted prices, which are Level 1 inputs within the fair value hierarchy. The carrying value of the Senior Credit Facility approximates its fair value because the interest rates are variable and reflective of market rates, which are Level 2 inputs within the fair value hierarchy.

The following table sets forth the carrying values and estimated fair values of our long-term indebtedness.

	December 31, 2012		December 31, 2011	
	(In thousands)			
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
2011 Notes	$ 205,125	$ 214,700	$ 204,390	$ 202,700
2012 Notes	289,786	309,900	-	-
Senior Credit Facility	195,000	195,000	-	-
Total	$ 689,911	$ 719,600	$ 204,390	$ 202,700

We evaluate our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicate that the carrying values may not be recoverable. Our assessment of possible impairment of proved oil and natural gas properties is based on our best estimate of future prices, costs and expected net future cash flows by property (generally analogous to a field or lease). An impairment loss is indicated if undiscounted net future cash flows are less than the carrying value of a property. The impairment expense is measured as the shortfall between the net book value of the property and its estimated fair value, which is measured based on the discounted net future cash flows from the property. The inputs used to estimate the fair value of our oil and natural gas properties are based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors. These inputs meet the definition of Level 3 inputs within the fair value hierarchy. Impairments for the year ended December 31, 2012 were primarily due to the decline in our estimate of future natural gas prices, which affected three of our natural gas producing fields and reservoir performance at two of those fields. These fields were determined to have future net cash flows less than their carrying values resulting in the write downs of these properties to their estimated fair values. We also recorded impairments for undeveloped leases that are expiring in 2013 for which we have no development plans. Impairments for the year ended December 31, 2011 were primarily related to our natural gas producing fields and our deepwater producing well (primarily natural gas). Impairments related to our deepwater producing well were primarily due to the decline in our estimate of future natural gas prices, reservoir performance and higher estimated operating costs. Additional impairments for the year ended December 31, 2011 were primarily related to reservoir performance at other natural gas producing fields.

As addressed in Note 2, “Acquisitions,” we apply fair value concepts in estimating and allocating the fair value of assets acquired and liabilities assumed in acquisitions in accordance with purchase accounting for business combinations. The inputs to the estimated fair values of assets acquired and liabilities assumed are described in Note 2.

(11) Income Taxes

The following table sets forth the components of our income tax benefit (expense).

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Current:			
Federal	$ -	$ -	$ -
State	-	-	-
Total current	$ -	$ -	$ -
Deferred:			
Federal	$ (28,719)	$ (14,468)	$ 4,248
State	(1,181)	(354)	161
Total deferred	$ (29,900)	$ (14,822)	$ 4,409
Total:			
Federal	$ (28,719)	$ (14,468)	$ 4,248
State	(1,181)	(354)	161
Total income tax benefit (expense)	$ (29,900)	$ (14,822)	$ 4,409

The following table reconciles the expected statutory federal income tax rate to our effective income tax rate.

	Percentage of Pretax Earnings		
	Year Ended December 31,		
	2012	2011	2010
Expected statutory federal income tax rate	35.0 %	35.0 %	35.0 %
State taxes	1.4	2.3	2.6
State tax rate changes	(2.7)	(1.7)	(3.6)
Statutory depletion	(0.4)	(1.0)	3.4
Other	0.4	1.2	(3.2)
Effective income tax rate	33.7 %	35.8 %	34.2 %

The following table sets forth the tax effects of temporary differences that give rise to significant portions of the current tax asset and net deferred tax liability.

	December 31, 2012		2011	
	(In thousands)			
Current deferred tax assets (liabilities):				
Fair value of commodity derivative instruments	$	3,865	$	175
Prepaid assets		(1,779)		(1,435)
Accruals and other		1,236		(1,563)
Net current deferred tax asset (liability)		3,322		(2,823)
Non-current deferred tax assets:				
Restricted stock awards and options	$	2,313	$	1,272
Federal and state net operating loss carryforwards		60,406		60,266
Fair value of commodity derivative instruments		-		71
Percentage depletion carryforward		4,211		4,105
Other		57		943
Non-current deferred tax asset		66,987		66,657
Non-current deferred tax liabilities:				
Property, plant and equipment, principally due to differences in depreciation		(134,681)		(98,432)
Net non-current deferred tax liability	$	(67,694)	$	(31,775)

As a result of our reorganization under Chapter 11 in 2009, the income from the discharge of indebtedness, represented for tax purposes as the excess of the principal and accrued interest on the debt discharged over the fair value of the stock of the reorganized company received in exchange for the discharged obligations, as defined by Internal Revenue Code (the

"IRC") Section 108 ("IRC 108"), reduced our net operating loss carryforwards ("NOLs") by $97 million ("Tax Attribute Reduction"). Our remaining NOLs as of December 31, 2012 were approximately $164.0 million.

Ownership changes, as defined in IRC Section 382, limit the amount of NOLs that can be utilized annually to offset future taxable income and reduce our tax liability ("Section 382 Limitation"). In 2009, as part of our Chapter 11 reorganization, we had an ownership change which resulted in a Section 382 Limitation on the amount of NOLs available annually for use. Unused annual limited NOLs (those NOLs in existence immediately after the application of IRC 108) totaled $137 million. The annual limitation is approximately $21 million per year beginning in 2010 and, if unused, can be carried over and aggregated with limited NOLs in future years subject to the ultimate expiration of the NOLs. We have not used any limited NOLs since the reorganization. The amount of limited NOLs available for our 2012 federal tax return is approximately $69 million. We believe that we will be able to utilize all of our federal NOLs prior to their expiration.

Our federal NOLs of approximately $164.0 million as of December 31, 2012 are available to reduce future federal taxable income subject to the limitations and estimates described above and the application of the tax rules and regulations. The NOLs begin expiring in the years 2025 through 2032.

As of January 1, 2012, our 2008-2011 income tax years remain subject to examination by the Internal Revenue Service. In addition, our 2008-2011 state income/franchise tax years remain subject to examination by the States of Louisiana and Texas. As of the date of these financial statements, our 2012 U.S. federal and state income tax returns have not been filed, although management expects to file such returns in a timely manner during 2013. We have no material uncertain tax positions as of December 31, 2012.

(12) Employee Benefit Plans

Share-Based Compensation Plans

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

The maximum aggregate number of shares of our common stock that may be issued pursuant to any and all Awards under the 2009 LTIP is limited to 2,474,000 shares, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or the expiration of Awards, as provided under the 2009 LTIP. As of December 31, 2012, 679,608 shares remained available for future grants.

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

The 2009 LTIP provides for the grant of stock options for which the exercise price, set at the time of the grant, will not be less than the fair market value per share at the date of grant. Our outstanding stock options generally have a term of 10 years and vest ratably on an annual basis over a three-year period from the date of grant, other than the stock option grant to our chief executive officer described in the following paragraph.

Pursuant to an employment agreement and the 2009 LTIP, on September 30, 2009, our new chief executive officer was granted an option to purchase 68,116 shares of our common stock, which was memorialized in an option award agreement dated as of October 1, 2009 (the "Option Agreement"). The terms of the Option Agreement provided for an exercise price equal to $10.00 per share. The closing price of our common stock on the NYSE on September 30, 2009 was $7.46 per share. The option vested ratably on a monthly basis over a 36-month period from the date of grant; however, the vesting for the first six months of the vesting period (the "Initial Period") was deferred until the end of the Initial Period and any remaining unvested portion vested ratably on a monthly basis over the remainder of the 36-month vesting period, subject to the executive remaining continuously employed. Under the original terms of the award agreement, vested stock options under the Option Agreement were to expire 30 months following the applicable vesting date of such stock options. On May 1, 2012, the Compensation Committee modified the terms of the Option Agreement to extend the expiration of the stock options granted thereunder to September 30, 2019, resulting in additional compensation expense of $0.1 million in the year ended December 31, 2012. Upon a change in control as defined in the 2009 LTIP, all remaining unvested stock options under the

Option Agreement automatically vest and remain exercisable for a period of not less than 30 months following the change in control.

Pursuant to the 2009 LTIP, on the date of the 2012 Annual Meeting of Stockholders, the five members of the Board of Directors were awarded, in the aggregate, a total of 31,095 shares of restricted stock, of which one-half vested immediately and one-half will vest on the day immediately preceding the date of the 2013 Annual Meeting of Stockholders. Pursuant to the 2009 LTIP, on the date of the 2011 Annual Meeting of Stockholders, the five members of the Board of Directors were awarded, in the aggregate, a total of 31,405 shares of restricted stock, of which one-half vested immediately and one-half vested on the day immediately preceding the date of the 2012 Annual Meeting of Stockholders. Pursuant to the 2009 LTIP, on the date of the 2010 Annual Meeting of Stockholders, the five members of the Board of Directors were awarded, in the aggregate, a total of 42,735 shares of restricted stock, of which one-half vested immediately and one-half vested on the day immediately preceding the date of the 2011 Annual Meeting of Stockholders. Pursuant to elections made by two directors applicable to certain awards, the receipt of such awards totaling 32,887 shares is deferred until such directors cease to serve on our Board of Directors.

The following table sets forth our stock option activity for the year ended December 31, 2012.

	Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Terms (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding on December 31, 2011	934,013	$ 13.05		
Granted	338,204	16.94		
Exercised	(48,130)	9.16		
Forfeited/Cancelled	(31,929)	13.62		
Outstanding on December 31, 2012	1,192,158	$ 14.30	8.2	$ 9,836
Exercisable on December 31, 2012	427,374	$ 12.47	7.4	$ 4,310

The fair value of each stock option award was estimated on the date of grant using the Black-Scholes option valuation model using the weighted average assumptions in the table below.

	Year Ended December 31,		
	2012	2011	2010
Black-Scholes option pricing model assumptions:			
Risk free interest rate	1.0 %	1.9 %	2.9 %
Expected life (years)	6.0	6.0	6.0

Expected volatility	56 %	53 %	50 %
Dividend yield	-	-	-

Expected volatility is generally based on the historical volatility of our stock over the period of time equivalent to the expected term of the options granted. As a result of our Chapter 11 reorganization in 2009 for purposes of determining expected volatility in 2012, 2011 and 2010, we included consideration of the historical volatility of the share prices of our peers over the relevant time periods in addition to our historical volatility before, during and after our reorganization. We disregarded our share price for the periods during which our stock price was impacted by factors leading up to the Chapter 11 filing and during the period of the Chapter 11 reorganization proceedings because we do not expect these events to reoccur during the expected term of the options. The expected term of options granted is generally derived from historical exercise patterns over a period of time, with consideration of expected term of unvested options. However, because we do not have sufficient historical stock option exercise experience upon which to base an estimate of expected term, we used the simplified method for estimating expected term in 2012, 2011 and 2010. The risk-free interest rate is based on the interest rate on constant maturity bonds published by the Federal Reserve with a maturity commensurate with the expected term of the options granted.

The weighted-average grant-date fair value of stock options granted during the years ended December 31, 2012, 2011 and 2010 was $8.84, $7.97 and $5.32, respectively. The aggregate intrinsic value (the amount by which the market price of the stock on the date of exercise exceeded the market price of the stock on the date of grant) of stock options exercised during the years ended December 31, 2012 and 2011 was $0.5 million and $0.1 million, respectively. No stock options were exercised during the year ended December 31, 2010.

The following table sets forth the activity related to our non-vested share awards for the year ended December 31, 2012.

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested share awards outstanding at December 31, 2011	185,733	$ 15.25
Granted	238,199	16.33
Vested	(86,834)	15.52
Forfeited	(10,146)	15.04
Non-vested share awards outstanding at December 31, 2012	326,952	$ 15.98

The fair value of non-vested share awards equals the market value of the underlying stock on the date of grant. The weighted-average grant-date fair value of the non-vested share awards granted during the years ended December 31, 2012, 2011 and 2010 was $16.33, $15.34 and $11.70 per share, respectively. The total fair value of non-vested share awards that vested during the years ended December 31, 2012, 2011 2010 was $2.0 million, $0.6 million and $0.5 million, respectively.

The following table sets forth share-based compensation expense and related recognized tax benefits.

	Year Ended December 31,		
	2012	2011	2010
Compensation Expense:			
Stock Options	$ 2,621	$ 1,497	673
Non-vested share awards	2,096	1,012	500
Employee bonus share awards	-	-	82
Deferred Income Tax Benefit	1,726	936	429

As of December 31, 2012, $3.9 million of total unrecognized compensation expense related to outstanding stock options was expected to be recognized over a weighted-average period of 2.0 years. As of December 31, 2012, $3.4 million of total unrecognized compensation expense related to non-vested share awards was expected to be recognized over a weighted-average period of approximately 2.0 years.

401(K) Plan

We also have a 401(K) Plan that covers all employees. We match 100% of each individual participant’s contribution not to exceed 6% of the participant’s compensation. Our matching contributions are made in cash. During the years ended December 31, 2012, 2011 and 2010, we made matching contributions to the 401(K) Plan of approximately $0.8 million, $0.7 million and $0.6 million, respectively.

Employee Retention Plans

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

(13) Commitments and Contingencies

We have operating leases for office space and equipment, which expire on various dates through 2017. Future minimum commitments as of December 31, 2012 under these operating obligations are as follows (in thousands):

2013	$ 894
2014	960
2015	961
2016	973
2017	78
Future minimum commitments	$ 3,866

Expense relating to operating obligations for the years ended December 31, 2012, 2011 and 2010 was $2.4 million, $1.8 million and $1.5 million, respectively.

We maintain restricted escrow funds in a trust for future abandonment costs at our East Bay property. The trust was originally funded with $15.0 million and, with accumulated interest, increased to $16.7 million at December 31, 2008. We may draw from the trust upon completion of qualifying abandonment activities at our East Bay field. At December 31, 2012, we had $6.0 million remaining in restricted escrow funds for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our consolidated balance sheets.

We record liabilities when we deliver production that is in excess of our interest in certain properties. In addition to these imbalances, we may, from time to time, be allocated cash sales proceeds in excess of amounts that we estimate are due to us for our interest in production. These allocations may be subject to further review, may require more information to resolve or may be in dispute. In July 2010, we were notified by a purchaser of oil production from one of our non-operated fields that we were allocated, and received sales proceeds from, more oil production than we actually sold to that purchaser. These third party misallocations may date back to 2006. The oil purchaser’s initial estimate of the oil volumes misallocated to us was approximately 74,000 barrels, which may be valued at up to $6.9 million based on information provided by the oil purchaser. We have previously recorded an amount that we believe may be payable related to a potential reallocation, which amount is reflected in Accrued expenses in the accompanying condensed consolidated balance sheets as of December 31, 2012 and 2011.

We and our oil and gas joint interest owners are subject to periodic audits of the joint interest accounts for leases in which we participate and/or operate. As a result of these joint interest audits, amounts payable or receivable by us for costs incurred or revenue distributed by the operator or by us on a lease may be adjusted, resulting in adjustments, increases or decreases, to our net costs or revenues and the related cash flows. Such adjustments may be material. When they occur, these adjustments are recorded in the current period, which generally is one or more years after the related cost or revenue was incurred or recognized by the joint account.

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

(14) Interim Financial Information (Unaudited)

The following tables summarize our consolidated unaudited interim financial information for the years ended December 31, 2012 and 2011.

	Three Months Ended			
	March 31	June 30	September 30	December 31 [1]
	(In thousands, except per share data)			
2012				
Revenues	$ 98,796	$ 99,270	$ 86,668	$ 138,899
Costs and expenses	71,501	68,071	67,379	86,235
Income from operations	27,295	31,199	19,289	52,664
Net income (loss)	1,503	35,401	(2,247)	24,153
Earnings (loss) per share:				
Basic	$ 0.04	$ 0.90	$ (0.06)	$ 0.62
Diluted	0.04	0.90	(0.06)	0.61

(1) Includes the results of operations of the Hilcorp Properties, which we acquired on October 31, 2012.

	Three Months Ended			
	March 31 [1]	June 30	September 30	December 31
	(In thousands, except per share data)			
2011				
Revenues	$ 67,249	$ 92,830	$ 84,884	$ 103,364
Costs and expenses	60,175	61,571	69,232	90,223
Income from operations	7,074	31,259	15,652	13,141
Net income (loss)	(14,509)	25,003	23,458	(7,341)
Earnings (loss) per share:				
Basic	$ (0.36)	$ 0.62	$ 0.59	$ (0.19)
Diluted	(0.36)	0.62	0.58	(0.19)

(1) Included in net income (loss) for the three months ended March 31 is the loss on extinguishment of debt of $2.4 million resulting from writing off the unamortized deferred financing costs associated with our terminated amended prior credit facility.

(15) Supplementary Oil and Natural Gas Disclosures—(Unaudited)

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

Our estimates of proved reserves are based on reserve reports prepared as of December 31, 2012 by independent petroleum engineering firms Netherland, Sewell & Associates, Inc. and W.D. Von Gonten & Co. Users of this information should be aware that the process of estimating quantities of “proved” and “proved developed” natural gas and crude oil reserves is very complex, requiring significant professional judgment in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the professional judgment required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be

expected to be recovered through existing wells with existing equipment and operating methods.

The following table sets forth our estimated net proved reserves, changes in our estimated net proved reserves and our proved developed reserves.

	Crude Oil (Mbbls)	Gas (Mmcf)	Oil Equivalent (Mboe)
Estimated Proved Reserves:			
December 31, 2009	19,923	67,378	31,153
Extensions, discoveries and other additions	652	489	733
Revisions (a)	(1,016)	8,892	466
Production	(2,336)	(15,508)	(4,921)
December 31, 2010	17,223	61,251	27,431
Acquisitions (b)	7,987	8,640	9,427
Extensions, discoveries and other additions	2,266	4,664	3,043
Revisions	2,778	(6,678)	1,666
Production	(2,953)	(9,092)	(4,468)
December 31, 2011	27,301	58,785	37,099
Acquisitions (c)	16,430	115,876	35,742
Extensions, discoveries and other additions	6,388	10,241	8,095
Revisions	1,128	4,033	1,800
Production	(3,805)	(8,996)	(5,304)
December 31, 2012	47,442	179,939	77,432
Proved developed reserves:			
December 31, 2010	15,974	56,410	25,376
December 31, 2011	24,791	52,739	33,581
December 31, 2012	37,908	120,687	58,022

(a) Crude oil revisions and natural gas revisions include decreases of approximately 3,093 Mbbls and 7,360 Mmcf, respectively, related to PUDs aged greater than five years for which funds were not committed in our 2011 development plan. Crude oil revisions also include a net increase of approximately 2,077 Mbbls primarily related to the crude oil price increase. Natural gas revisions also include positive revisions of 26,163 Mmcf related to the inclusion of estimated fuel gas in our natural gas reserves in the December 31, 2010 reserve volumes. This change in methodology reflects fuel gas as a production cost rather than negative natural gas reserves and does not impact future net cash flows after income taxes or standardized measure of discounted future net cash flows. The positive revisions related to the one-time change in the fuel gas methodology were partially offset by decreases of 7,813 Mmcf associated with underperformance of certain wells.

(b) Reserves acquired in the acquisitions of the ASOP Properties and Main Pass Interests.

(c) Reserves acquired in the acquisitions of the Hilcorp Properties and the ST41 Interests.

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

	Year Ended December 31,	
	2012	2011
	(In thousands)	
Proved properties	$ 1,982,657	$ 1,049,140
Unproved properties	36,992	29,382
Accumulated depreciation, depletion and amortization	(424,520)	(303,566)
Net capitalized costs	$ 1,595,129	$ 774,956

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

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Acquisitions — Proved (1)	$ 706,322	$ 261,812	$ -
Acquisitions — Unproved	7,496	14	623
Exploration	43,338	17,129	31,463
Development (2)	180,938	83,577	25,643
Costs incurred	$ 938,094	$ 362,532	$ 57,729

(1) Includes asset retirement obligations associated with acquisitions totaling $132.1 million and $26.4 million during the years ended December 31, 2012 and 2011, respectively.

(2) Includes asset retirement obligations incurred associated with finding, acquiring and developing our proved oil and natural gas reserves of $1.2 million, $0.2 million and $0.1 million during the years ended December 31, 2012, 2011 and 2010, respectively.

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

Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves

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

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

The Standardized Measure of Discounted Future Net Cash Flows uses future cash inflows estimated using oil and natural gas prices computed by applying the use of physical pricing based on the simple average of the closing price on the first day of each of the twelve months during the fiscal year (as required by ASC 932) and by applying historical adjustments, including transportation, quality differentials, and purchaser bonuses, on an individual property basis, to the year-end quantities of estimated proved reserves. The historical adjustments applied to the computed prices are determined by comparing our historical realized price experience with the comparable historical market, or posted, price. These adjustments can vary significantly over time both in amount and as a percentage of the posted

price, especially related to our oil prices during periods when the market price for oil varies widely. The price adjustments reflected in our computed reserve prices may not represent the amount of price adjustments we may actually obtain in the future when we sell our production, nor do they give effect to any hedging transactions that we may enter into. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs with the assumption of the continuation of existing economic conditions in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying period-end statutory tax rates to aggregate future net cash flows, reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% annual discount rate in computing Standardized Measure of Discounted Future Net Cash Flows is required by ASC 932.

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

	Year Ended December 31,	
	2012	2011
	(In thousands)	
Future cash inflows	$ 5,401,290	$ 3,133,430
Future production costs	(1,823,303)	(1,141,297)
Future development costs [1]	(936,580)	(437,074)
Future income taxes	(537,546)	(322,454)
Future net cash flows after income taxes	2,103,861	1,232,605
10% annual discount for estimated timing of cash flows	(529,579)	(356,436)
Standardized measure of discounted future net cash flows	$ 1,574,282	$ 876,169

(1) Development costs for the year ended December 31, 2012, include $466.9 million of estimated abandonment and decommissioning costs, net of $32.6 million of estimated salvage values. Development costs for the year ended December 31, 2011 include $203.7 million of estimated abandonment and decommissioning costs, net of $30.6 million of estimated salvage values.

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the years ended December 31, 2012 and 2011 is as follows:

	Year Ended December 31,	
	2012	2011
	(In thousands)	
Beginning of the period	$ 876,169	$ 359,458
Sales and transfers of oil and natural gas produced, net of production costs	(317,059)	(266,120)
Net changes in prices and production costs	(244,824)	461,719
Purchase of minerals in place	797,085	230,471
Extensions, discoveries and improved recoveries, net of future production costs	452,258	139,757
Revision of quantity estimates	55,133	54,329
Previously estimated development costs incurred during the period	39,321	27,066
Changes in estimated future development costs	746	24,662
Changes in production rates (timing) and other	(14,157)	(25,655)
Accretion of discount	110,070	41,307
Net change in income taxes	(180,460)	(170,825)
Net increase (decrease)	698,113	516,711
End of period	$ 1,574,282	$ 876,169

At December 31, 2012 and 2011, the computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on the following computed prices:

	2012	2011
per barrel of oil	$ 105.13	$ 108.48
per Mcf for natural gas	$ 2.92	$ 4.16

(16) Supplemental Condensed Consolidating Financial Information

In connection with the offering of the 2011 Senior Notes and the 2012 Senior Notes described in Note 7, all of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries) each of which is 100% owned by EPL Oil & Gas, Inc. (the "Guarantor Subsidiaries") jointly and severally guarantee the payment obligations under our 2011 Senior Notes and 2012 Senior Notes. The guarantees are full and unconditional, as those terms are used in Rule 3-10 of Regulation S-X, except that a Guarantor Subsidiary can be automatically released and relieved of its obligations under certain customary circumstances contained in the indentures governing the 2011 Senior Notes and the 2012 Senior Notes. So long as other applicable provisions of the indentures are adhered to, these customary circumstances include: when a Guarantor Subsidiary is declared "unrestricted" for covenant purposes, when the requirements for legal defeasance or covenant defeasance or to discharge the indenture have been satisfied, or when the Guarantor Subsidiary is sold or sells all of its assets. The following supplemental financial information sets forth, on a consolidating basis, the balance sheets, statements of operations and cash flow information for EPL Oil & Gas, Inc. (Parent Company Only) and for the Guarantor Subsidiaries. We have not presented separate financial statements and other disclosures concerning the Guarantor Subsidiaries because management has determined that such information is not material to investors.

The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements. Certain reclassifications were made to conform all of the financial information to the financial presentation on a consolidated basis. The principal eliminating entries eliminate investments in subsidiaries, intercompany balances and intercompany revenues and expenses.

Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 1,521	$ -	$ -	$ 1,521
Trade accounts receivable - net	66,994	997	-	67,991
Intercompany receivables	55,575	-	(55,575)	-
Fair value of commodity derivative instruments	3,302	-		3,302
Deferred tax asset	3,322	-	-	3,322
Prepaid expenses	9,873	-		9,873
Total current assets	140,587	997	(55,575)	86,009
Property and equipment	1,754,294	271,353	-	2,025,647
Less accumulated depreciation, depletion, amortization and impairments	(353,526)	(74,054)	-	(427,580)
Net property and equipment	1,400,768	197,299	-	1,598,067
Investment in affiliates	111,191	-	(111,191)	-
Restricted cash	6,023	-	-	6,023
Fair value of commodity derivative instruments	211	-	-	211
Deferred financing costs	12,386	-	-	12,386
Other assets	2,841	90	-	2,931
Total assets	$ 1,674,007	$ 198,386	$ (166,766)	$ 1,705,627
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$ 34,740	$ 32	$ -	$ 34,772
Intercompany payables	-	55,575	(55,575)	-
Accrued expenses	117,245	127	-	117,372
Asset retirement obligations	23,982	6,197	-	30,179
Fair value of commodity derivative instruments	10,026	-	-	10,026
Total current liabilities	185,993	61,931	(55,575)	192,349
Long-term debt	689,911	-	-	689,911
Asset retirement obligations	187,790	17,141	-	204,931
Deferred tax liabilities	59,571	8,123	-	67,694
Fair value of commodity derivative instruments	3,637	-	-	3,637
Other	1,132	-	-	1,132
Total liabilities	1,128,034	87,195	(55,575)	1,159,654
Stockholders' equity:				
Preferred stock	-	-	-	-
Common stock	40	-	-	40

Additional paid-in capital	510,469	85,479	(85,479)	510,469
Treasury stock, at cost	(20,477)	-	-	(20,477)
Retained earnings (accumulated deficit)	55,941	25,712	(25,712)	55,941
Total stockholders’ equity	545,973	111,191	(111,191)	545,973
Total liabilities and stockholders' equity	$ 1,674,007	$ 198,386	$ (166,766)	$ 1,705,627

Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 80,128	$ -	$ -	$ 80,128
Trade accounts receivable - net	31,686	131	-	31,817
Intercompany receivables	62,196	-	(62,196)	-
Fair value of commodity derivative instruments	587	-	-	587
Prepaid expenses	11,046	-	-	11,046
Total current assets	185,643	131	(62,196)	123,578
Property and equipment	833,932	248,316	-	1,082,248
Less accumulated depreciation, depletion, amortization and impairments	(251,948)	(53,162)	-	(305,110)
Net property and equipment	581,984	195,154	-	777,138
Investment in affiliates	91,768	-	(91,768)	-
Notes receivable, long-term	-	69,000	(69,000)	-
Restricted cash	6,023	-	-	6,023
Deferred financing costs	5,452	-	-	5,452
Other assets	3,029	-	-	3,029
Total assets	$ 873,899	$ 264,285	$ (222,964)	$ 915,220
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$ 24,380	$ 1,013	$ -	$ 25,393
Intercompany payables	-	62,196	(62,196)	-
Accrued expenses	58,538	-	-	58,538
Asset retirement obligations	16,178	9,400	-	25,578
Fair value of commodity derivative instruments	1,056	-	-	1,056
Deferred tax liabilities	2,823	-	-	2,823
Total current liabilities	102,975	72,609	(62,196)	113,388
Long-term debt	204,390	69,000	(69,000)	204,390
Asset retirement obligations	50,805	22,964	-	73,769
Deferred tax liabilities	23,831	7,944	-	31,775
Fair value of commodity derivative instruments	190	-	-	190
Other	663	-	-	663
Total liabilities	382,854	172,517	(131,196)	424,175
Stockholders' equity:				
Preferred stock	-	3	(3)	-
Common stock	40	98	(98)	40
Additional paid-in capital	505,235	84,900	(84,900)	505,235
Treasury stock	(11,361)	-	-	(11,361)

Retained earnings (accumulated deficit)	(2,869)	6,767	(6,767)	(2,869)
Total stockholders’ equity	491,045	91,768	(91,768)	491,045
Total liabilities and stockholders' equity	$ 873,899	$ 264,285	$ (222,964)	$ 915,220

Supplemental Condensed Consolidating Statement of Operations

Year Ended December 31, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 318,749	$ 103,780	$ -	$ 422,529
Other	15,152	952	(15,000)	1,104
Total revenue	333,901	104,732	(15,000)	423,633
Costs and expenses:				
Lease operating	71,002	23,848	-	94,850
Transportation	611	4	-	615
Exploration expenditures and dry hole costs	18,790	9	-	18,799
Impairments	8,883	-	-	8,883
Depreciation, depletion and amortization	92,689	20,892	-	113,581
Accretion of liability for asset retirement obligations	10,551	5,014	-	15,565
General and administrative	22,845	15,363	(15,000)	23,208
Taxes, other than on earnings	1,162	11,845	-	13,007
Other	5,496	(818)	-	4,678
Total costs and expenses	232,029	76,157	(15,000)	293,186
Income from operations	101,872	28,575	-	130,447
Other income (expense):				
Interest income	136	-	-	136
Interest expense	(28,568)	-	-	(28,568)
Loss on derivative instruments	(13,305)	-	-	(13,305)
Income from equity investments	18,945	-	(18,945)	-
Total other income (expense)	(22,792)	-	(18,945)	(41,737)
Income before provision for income taxes	79,080	28,575	(18,945)	88,710
Provision for income taxes:				
Current	-	-	-	-
Deferred	(20,270)	(9,630)	-	(29,900)
Total provision for income taxes	(20,270)	(9,630)	-	(29,900)
Net income	$ 58,810	$ 18,945	$ (18,945)	$ 58,810

Supplemental Condensed Consolidating Statement of Operations

Year Ended December 31, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 245,567	$ 102,640	$ -	$ 348,207
Other	15,007	113	(15,000)	120
Total revenue	260,574	102,753	(15,000)	348,327
Costs and expenses:				
Lease operating	51,618	18,663	-	70,281
Transportation	766	13	-	779
Exploration expenditures and dry hole costs	14,045	223	-	14,268
Impairments	32,532	(66)	-	32,466
Depreciation, depletion and amortization	82,168	22,456		104,624
Accretion of liability for asset retirement obligations	9,013	6,929		15,942
General and administrative	18,281	15,460	(15,000)	18,741
Taxes, other than on earnings	(733)	15,098	-	14,365
Other	9,940	(205)	-	9,735
Total costs and expenses	217,630	78,571	(15,000)	281,201
Income from operations	42,944	24,182	-	67,126
Other income (expense):				
Interest income	102	-	-	102
Interest expense	(17,548)	-	-	(17,548)
Loss on derivative instruments	(5,870)	-	-	(5,870)
Loss on early extinguishment of debt	(2,377)	-	-	(2,377)
Income from equity investments	15,532	-	(15,532)	-
Total other income (expense)	(10,161)	-	(15,532)	(25,693)
Income before provision for income taxes	32,783	24,182	(15,532)	41,433
Provision for income taxes:				
Current	-	-	-	-
Deferred	(6,172)	(8,650)	-	(14,822)
Total provision for income taxes	(6,172)	(8,650)	-	(14,822)
Net income	$ 26,611	$ 15,532	$ (15,532)	$ 26,611

Supplemental Condensed Consolidating Statement of Operations

Year Ended December 31, 2010

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 171,176	$ 68,594	$ -	$ 239,770
Other	15,008	131	(15,000)	139
Total revenue	186,184	68,725	(15,000)	239,909
Costs and expenses:				
Lease operating	34,004	18,361	-	52,365
Transportation	1,306	-	-	1,306
Exploration expenditures and dry hole costs	3,237	3,204		6,441
Impairments	25,478	664		26,142
Depreciation, depletion and amortization	83,672	20,889		104,561
Accretion of liability for asset retirement obligations	6,018	6,827	-	12,845
General and administrative	17,737	15,341	(15,000)	18,078
Taxes, other than on earnings	681	9,452	-	10,133
Other	897	(168)	-	729
Total costs and expenses	173,030	74,570	(15,000)	232,600
Income from operations	13,154	(5,845)	-	7,309
Other income (expense):				
Interest income	113	-	-	113
Interest expense	(9,807)	-	-	(9,807)
Loss on derivative instruments	(4,865)			(4,865)
Loss on early extinguishment of debt	(5,627)			(5,627)
Loss from equity investments	(3,846)	-	3,846	-
Total other income (expense)	(24,032)	-	3,846	(20,186)
Loss before provision for income taxes	(10,878)	(5,845)	3,846	(12,877)
Provision for income taxes:				
Current	-	-	-	-
Deferred	2,410	1,999	-	4,409
Total provision for income taxes	2,410	1,999	-	4,409
Net income (loss)	$ (8,468)	$ (3,846)	$ 3,846	$ (8,468)

Supplemental Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$ 190,851	$ 23,020	$ -	$ 213,871
Cash flows provided by (used in) investing activities:				
Property acquisitions	(575,372)	(3,000)	-	(578,372)
Exploration and development expenditures	(165,308)	(19,542)	-	(184,850)
Other property and equipment additions	(1,265)	(478)	-	(1,743)
Net cash used in investing activities	(741,945)	(23,020)	-	(764,965)
Cash flows provided by (used in) financing activities:				
Proceeds from indebtedness	509,313	-	-	509,313
Repayments of indebtedness	(20,000)	-	-	(20,000)
Deferred financing costs	(8,469)	-	-	(8,469)
Purchase of shares into treasury	(8,798)	-	-	(8,798)
Exercise of stock options	441	-	-	441
Net cash provided by financing activities	472,487	-	-	472,487
Net decrease in cash and cash equivalents	(78,607)	-	-	(78,607)
Cash and cash equivalents at beginning of period	80,128	-	-	80,128
Cash and cash equivalents at end of period	$ 1,521	$ -	$ -	$ 1,521

Supplemental Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2011

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$ 136,245	$ 35,007	$ -	$ 171,252
Cash flows provided by (used in) investing activities:				
Decrease in restricted cash	2,466	-	-	2,466
Property acquisitions	(235,486)	-	-	(235,486)
Exploration and development expenditures	(40,996)	(35,007)	-	(76,003)
Other property and equipment additions	(1,568)	-	-	(1,568)
Net cash used in investing activities	(275,584)	(35,007)	-	(310,591)
Cash flows provided by (used in) financing activities:				
Proceeds from indebtedness	203,794	-	-	203,794

Deferred financing costs	(6,646)	-	-	(6,646)
Purchase of shares into treasury	(11,353)	-	-	(11,353)
Exercise of stock options	119	-	-	119
Net cash provided by financing activities	185,914	-	-	185,914
Net increase in cash and cash equivalents	46,575	-	-	46,575
Cash and cash equivalents at beginning of period	33,553	-	-	33,553
Cash and cash equivalents at end of period	$ 80,128	$ -	$ -	$ 80,128

Supplemental Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2010

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$ 84,613	$ 42,767	$ -	$ 127,380
Cash flows provided by (used in) investing activities:				
Decrease in restricted cash	13,658	-	-	13,658
Exploration and development expenditures	(15,416)	(42,767)	-	(58,183)
Other property and equipment additions	(755)	-	-	(755)
Property acquisitions	(623)	-	-	(623)
Net cash used in investing activities	(3,136)	(42,767)	-	(45,903)
Cash flows provided by (used in) financing activities:				
Proceeds from indebtedness	20,394	-	-	20,394
Repayments of indebtedness	(94,882)	-	-	(94,882)
Deferred financing costs	(181)	-	-	(181)
Net cash used in financing activities	(74,669)	-	-	(74,669)
Net increase in cash and cash equivalents	6,808	-	-	6,808
Cash and cash equivalents at beginning of period	26,745	-	-	26,745
Cash and cash equivalents at end of period	$ 33,553	$ -	$ -	$ 33,553

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are designed to ensure that information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. This information is also accumulated and communicated to management, including our principal executive officer and our principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, under the supervision and with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the most recent fiscal quarter reported on herein. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2012.

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

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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with GAAP. In connection with our annual evaluation of internal control over financial reporting, our management, under the supervision and with the participation of our principal executive officer and principal financial officer, assessed the effectiveness as of December 31, 2012, of our internal control over financial reporting based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on that evaluation, our management, including our principal executive officer and principal financial officer, concluded that our internal controls over financial reporting were effective as of December 31, 2012.

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

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting and has issued an attestation report as of December 31, 2012. See “Report of Independent Registered Public Accounting Firm” in Part II, Item 8 of this Annual Report.

(c) Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Except as set forth below, for information required by Item 10 regarding our directors and executive officers, see the definitive Proxy Statement of EPL Oil & Gas, Inc. for the Annual Meeting of Stockholders to be held on or about April 30, 2013, which will be filed with the SEC and is incorporated herein by reference.

Code of Ethics

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

Item 11. Executive Compensation

For information required by Item 11, see the definitive Proxy Statement of EPL Oil & Gas, Inc. for the Annual Meeting of Stockholders to be held on or about April 30, 2013, which will be filed with the SEC and is incorporated herein by reference.

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

Except as set forth below, for information required by Item 12, see the definitive Proxy Statement of EPL Oil & Gas, Inc. for the Annual Meeting of Stockholders to be held on or about April 30, 2013, which will be filed with the SEC and is incorporated herein by reference.

Securities Authorized for Issuance under Equity Compensation Plans

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

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

For information required by Item 13, see the definitive Proxy Statement of EPL Oil & Gas, Inc. for the Annual Meeting of Stockholders to be held on or about April 30, 2013, which will be filed with the SEC and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

For information required by Item 14, see the definitive Proxy Statement of EPL Oil & Gas, Inc. for the Annual Meeting of Stockholders to be held on or about April 30, 2013, which will be filed with the SEC and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents to be filed as part of this Annual Report

1. Financial Statements

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

- Independent Registered Public Accounting Firms' Reports
- Consolidated Balance Sheets as of December 31, 2012 and 2011
- Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010
- Notes to the Consolidated Financial Statements

2. Financial Statement Schedules

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

3. Exhibits

EXHIBITS

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

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
2.0		10-Q	001-16179	2.0	5/6/2010	

	Second Amended Joint Plan of Reorganization of Energy Partners, Ltd. and certain of its Subsidiaries Under Chapter 11 of the Bankruptcy Code, as Modified as of September 16, 2009					
2.1	Purchase and Sale Agreement dated January 13, 2011, by and between Anglo-Suisse Offshore Partners, LLC and Energy Partners, Ltd.	8-K	001-16179	2.1	1/18/2011	
2.2	Purchase and Sale Agreement dated October 28, 2011, by and between Stone Energy Offshore, LLC and Energy Partners, Ltd.	8-K	001-16179	2.2	11/2/2011	
2.3	Purchase and Sale Agreement between Hilcorp Energy GOM Holdings, LLC, as Seller and EPL Oil & Gas, Inc., as Buyer, dated September 14, 2012	8-K	001-16179	2.1	9/18/2012	
2.4	Purchase and Sale Agreement dated May 15, 2012, by and between W&T Offshore, Inc. and Energy Partners, Ltd.	8-K	001-16179	2.1	5/21/2012	
3.1	Amended and Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 21, 2009	8-A/A	001-16179	3.1	9/21/2009	X
3.2	Third Amended and Restated Bylaws of EPL Oil & Gas, Inc.	8-K	001-16179	3.1	10/18/2012	
3.3	Certificate of Ownership and Merger filed with the Secretary of State of the State of Delaware, which became effective by its terms on September 1, 2012	8-K	001-16179	3.1	9/5/2012	
3.4	Composite copy of the Amended and Restated Certificate of Incorporation of EPL Oil & Gas, Inc., reflecting all amendments through September 1, 2012, the effective date of the certificate of ownership and merger					X
4.1	Indenture by and among Energy Partners, Ltd., as Issuer, the Guarantors named therein and U.S. Bank National Association, as Trustee dated February 14, 2011	8-K	001-16179	4.1	2/15/2011	

4.2	Supplemental Indenture by and among Anglo-Suisse Offshore Pipeline Partners, LLC, as a Guarantor, Energy Partners, Ltd., as Issuer, the other Guarantors named therein and U.S. Bank National Association, as Trustee dated March 14, 2011	S-4	333-175567	4.2	7/14/2011	
4.3	Second Supplemental Indenture by and among Hilcorp Energy GOM, LLC, as a Guarantor, EPL Oil & Gas, Inc., as Issuer, the other Guarantors named therein, and U.S. Bank National Association, as Trustee dated October 31, 2012					X
4.4	Indenture by and among EPL Oil & Gas, Inc., the Guarantors named therein and U.S. Bank National Association, as Trustee, dated October 25, 2012	8-K	001-16179	4.1	10/30/2012	
4.5	First Supplemental Indenture by and among Hilcorp Energy GOM, LLC, as a Guarantor, EPL Oil & Gas, Inc., as Issuer, the other Guarantors named therein, and U.S. Bank National Association, as Trustee dated October 31, 2012					X
10.1	Registration Rights Agreement by and among Energy Partners, Ltd., the Guarantors named therein and the initial purchasers named therein dated February 14, 2011	8-K	001-16179	10.1	2/15/2011	
10.2	Registration Rights Agreement, by and among EPL Oil & Gas, Inc., the Guarantors named therein and the initial purchasers named therein dated October 25, 2012	8-K	001-16179	10.1	10/30/2012	
10.3	Amended and Restated Credit Agreement by and among EPL Oil & Gas, Inc., as Borrower, Bank of Montreal, as Administrative Agent, and certain financial institutions party thereto, as Lenders, dated as of October 31, 2012	8-K	001-16179	10.1	11/6/2012	
10.4	Exchange Agreement between Energy Partners, Ltd. and Mellon Investor	8-K	001-16179	10.4	9/25/2009	

	Services LLC (operating with the service name BNY Shareowner Services), as Agent dated September 15, 2009				
10.5†	Change of Control Severance Plan effective as of March 24, 2005	8-K	001-16179	10.2	3/30/2005
10.6†	First Amendment to Change of Control Severance Plan effective as of September 13, 2006	8-K	001-16179	10.3	9/14/2006
10.7†	Second Amendment to Change of Control Severance Plan effective as of April 16, 2008	8-K	001-16179	10.3	5/8/2008
10.8†	Third Amendment to Change of Control Severance Plan dated November 13, 2008	8-K	001-16179	10.2	11/14/2008
10.9†	Fourth Amendment to Change of Control Severance Plan dated November 13, 2008	10-K	001-16179	10.8	3/11/2010
10.10†	Fifth Amendment to Change of Control Severance Plan	10-Q	001-16179	10.2	8/5/2010
10.11	Term sheet with the United States Department of the Interior, Minerals Management Service dated April 30, 2009	10-K	001-16179	10.6	8/5/2009
10.12†	Employment Agreement dated as of October 1, 2009 between Energy Partners, Ltd. and Gary Hanna	8-K	001-16179	10.1	10/6/2009
10.13†	First Amendment to Employment Agreement dated as of April 12, 2010 between Energy Partners, Ltd. and Gary Hanna	10-Q	001-16179	10.3	8/5/2010
10.14†	Option Award Agreement dated as of September 30, 2009 between Energy Partners, Ltd. and Gary Hanna	8-K	001-16179	10.2	10/6/2009
10.15†	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and John H. Peper	10-K	001-16179	10.5	8/5/2009
10.16†	Energy Partners, Ltd. 2009 Long Term Incentive Plan	S-8	333-162185	4.5	9/29/2009

10.17†	First Amendment to the Energy Partners, Ltd. 2009 Long Term Incentive Plan	10-K	001-16179	10.23	3/8/2012	
10.18†	Form of 2009 Long Term Incentive Plan Option Award Agreement	8-K	001-16179	10.5	9/25/2009	
10.19†	Form of 2009 Long Term Incentive Plan Restricted Stock Agreement	8-K	001-16179	10.6	9/25/2009	
10.20†	Form of Indemnification Agreement for Directors	8-K	001-16179	10.1	11/24/2009	
10.21†	Form of Indemnification Agreement for Officers	8-K	001-16179	10.2	11/24/2009	
10.22†	Energy Partners, Ltd. Board Compensation Program	8-K	001-16179	10.1	11/12/2009	
10.23†	Second Amended and Restated Stock and Deferral Plan for Non-Employee Directors, dated as of November 6, 2009	8-K	001-16179	10.2	11/12/2009	
10.24†	Form of Director Deferred Share Agreement	8-K	001-16179	10.3	11/12/2009	
10.25†	Employment Agreement dated as of February 1, 2012 between Energy Partners, Ltd. and John H. Peper	10-K	001-16179	10.24	3/8/2012	
16.1	Letter from KPMG LLP dated July 1, 2010, addressed to the Securities and Exchange Commission	8-K	001-16179	16.1	7/1/2010	
21.1	Subsidiaries of EPL Oil & Gas, Inc.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Netherland, Sewell & Associates, Inc					X
23.3	Consent of W.D. Von Gonten & Co.					X
31.1	Certification of Principal Executive Officer of EPL Oil & Gas, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2						X

	Certification of Principal Financial Officer of EPL Oil & Gas, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
32.1	Section 1350 Certification of Principal Executive Officer of EPL Oil & Gas, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	X
32.2	Section 1350 Certification of Principal Financial Officer of EPL Oil & Gas, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	X
99.1	Report of Independent Petroleum Engineers (Netherland, Sewell & Associates, Inc) dated as of February 19, 2013	X
99.2	Report of Independent Petroleum Engineers (W.D. Von Gonten & Co.) dated as of February 19, 2013	X
101.SCH	XBRL Taxonomy Extension Schema Document	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	X

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

“Boe” means barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

“Bcf” means one billion cubic feet.

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

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

“LOE” means lease operating expenditures.

“Mbbls” means one thousand barrels of oil or other liquid hydrocarbons.

“Mboe” means one thousand barrels of oil equivalent. 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.

“Mcf” means one thousand cubic feet of natural gas.

“Mmbbls” means one million barrels of oil or other liquid hydrocarbons.

“Mmboe” means one million barrels of oil equivalent.

“Mmbtu” means one million British Thermal Units.

“Mmcf” means one million cubic feet of natural gas.

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

“proved undeveloped reserves” means proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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

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

“PV-10” means the present value of estimated future net revenues computed by applying constant prices, computed in accordance with ASC 932, based on the unweighted, arithmetic average of the closing commodity price on the first day of each of the twelve months during the fiscal year, discounted at a rate of 10% per year on a pre-tax basis.

“standardized measure” means the present value of estimated future net revenues computed by applying constant prices, computed in accordance with ASC 932, based on the unweighted, arithmetic average of the closing commodity price on the first day of each of the twelve months during the fiscal year, discounted at a rate of 10% per year on a post-tax basis.

“sidetrack” refers to directional drilling from an existing wellbore to relocate, without having to drill to the depth at which the directional drilling commences, the bottom of the well in a different productive zone that is horizontally removed from the original well.

SIGNATURES

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

Dated: March 7, 2013 EPL OIL & GAS, INC.

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

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

Signature	Title	Date
/S/ GARY C. HANNA Gary C. Hanna	President, Chief Executive Officer and Director (Principal Executive Officer)	March 7, 2013
/S/ TIFFANY J. THOM Tiffany J. Thom	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 7, 2013
/S/ DAVID P. CEDRO David P. Cedro	Senior Vice President, Chief Accounting Officer, Treasurer and Secretary (Principal Accounting Officer)	March 7, 2013
/S/ CHARLES O. BUCKNER Charles O. Buckner	Director	March 7, 2013
/S/ SCOTT A. GRIFFITHS Scott A. Griffiths	Director	March 7, 2013
/S/ MARC MCCARTHY Marc McCarthy	Director	March 7, 2013

/S/ STEVEN J. PULLY Steven J. Pully	Director	March 7, 2013
/S/ WILLIAM F. WALLACE William F. Wallace	Director	March 7, 2013

INDEX TO EXHIBITS

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

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
2.0	Second Amended Joint Plan of Reorganization of Energy Partners, Ltd. and certain of its Subsidiaries Under Chapter 11 of the Bankruptcy Code, as Modified as of September 16, 2009	10-Q	001-16179	2.0	5/6/2010	
2.1	Purchase and Sale Agreement dated January 13, 2011, by and between Anglo-Suisse Offshore Partners, LLC and Energy Partners, Ltd.	8-K	001-16179	2.1	1/18/2011	
2.2	Purchase and Sale Agreement dated October 28, 2011, by and between Stone Energy Offshore, LLC and Energy Partners, Ltd.	8-K	001-16179	2.2	11/2/2011	
2.3	Purchase and Sale Agreement between Hilcorp Energy GOM Holdings, LLC, as Seller and EPL Oil & Gas, Inc., as Buyer, dated September 14, 2012	8-K	001-16179	2.1	9/18/2012	
2.4	Purchase and Sale Agreement dated May 15, 2012, by and between W&T Offshore, Inc. and Energy Partners, Ltd.	8-K	001-16179	2.1	5/21/2012	
3.1	Amended and Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 21, 2009	8-A/A	001-16179	3.1	9/21/2009	X
3.2	Third Amended and Restated Bylaws of EPL Oil & Gas, Inc.	8-K	001-16179	3.1	10/18/2012	
3.3	Certificate of Ownership and Merger filed with the Secretary of State of the State of Delaware, which became effective by its terms on September 1,	8-K	001-16179	3.1	9/5/2012	

	2012					
3.4	Composite copy of the Amended and Restated Certificate of Incorporation of EPL Oil & Gas, Inc., reflecting all amendments through September 1, 2012, the effective date of the certificate of ownership and merger					X
4.1	Indenture by and among Energy Partners, Ltd., as Issuer, the Guarantors named therein and U.S. Bank National Association, as Trustee dated February 14, 2011	8-K	001-16179	4.1	2/15/2011	
4.2	Supplemental Indenture by and among Anglo-Suisse Offshore Pipeline Partners, LLC, as a Guarantor, Energy Partners, Ltd., as Issuer, the other Guarantors named therein and U.S. Bank National Association, as Trustee dated March 14, 2011	S-4	333-175567	4.2	7/14/2011	
4.3	Second Supplemental Indenture by and among Hilcorp Energy GOM, LLC, as a Guarantor, EPL Oil & Gas, Inc., as Issuer, the other Guarantors named therein, and U.S. Bank National Association, as Trustee dated October 31, 2012					X
4.4	Indenture by and among EPL Oil & Gas, Inc., the Guarantors named therein and U.S. Bank National Association, as Trustee, dated October 25, 2012	8-K	001-16179	4.1	10/30/2012	
4.5	First Supplemental Indenture by and among Hilcorp Energy GOM, LLC, as a Guarantor, EPL Oil & Gas, Inc., as Issuer, the other Guarantors named therein, and U.S. Bank National Association, as Trustee dated October 31, 2012					X
10.1	Registration Rights Agreement by and among Energy Partners, Ltd., the Guarantors named therein and the initial purchasers named therein dated February 14, 2011	8-K	001-16179	10.1	2/15/2011	
10.2		8-K	001-16179	10.1	10/30/2012	

	Registration Rights Agreement, by and among EPL Oil & Gas, Inc., the Guarantors named therein and the initial purchasers named therein dated October 25, 2012				
10.3	Amended and Restated Credit Agreement by and among EPL Oil & Gas, Inc., as Borrower, Bank of Montreal, as Administrative Agent, and certain financial institutions party thereto, as Lenders, dated as of October 31, 2012	8-K	001-16179	10.1	11/6/2012
10.4	Exchange Agreement between Energy Partners, Ltd. and Mellon Investor Services LLC (operating with the service name BNY Shareowner Services), as Agent dated September 15, 2009	8-K	001-16179	10.4	9/25/2009
10.5†	Change of Control Severance Plan effective as of March 24, 2005	8-K	001-16179	10.2	3/30/2005
10.6†	First Amendment to Change of Control Severance Plan effective as of September 13, 2006	8-K	001-16179	10.3	9/14/2006
10.7†	Second Amendment to Change of Control Severance Plan effective as of April 16, 2008	8-K	001-16179	10.3	5/8/2008
10.8†	Third Amendment to Change of Control Severance Plan dated November 13, 2008	8-K	001-16179	10.2	11/14/2008
10.9†	Fourth Amendment to Change of Control Severance Plan dated November 13, 2008	10-K	001-16179	10.8	3/11/2010
10.10†	Fifth Amendment to Change of Control Severance Plan	10-Q	001-16179	10.2	8/5/2010
10.11	Term sheet with the United States Department of the Interior, Minerals Management Service dated April 30, 2009	10-K	001-16179	10.6	8/5/2009
10.12†	Employment Agreement dated as of October 1, 2009 between Energy Partners, Ltd. and Gary Hanna	8-K	001-16179	10.1	10/6/2009

10.13†	First Amendment to Employment Agreement dated as of April 12, 2010 between Energy Partners, Ltd. and Gary Hanna	10-Q	001-16179	10.3	8/5/2010
10.14†	Option Award Agreement dated as of September 30, 2009 between Energy Partners, Ltd. and Gary Hanna	8-K	001-16179	10.2	10/6/2009
10.15†	Settlement Agreement dated as of June 23, 2009 by and between Energy Partners, Ltd. and John H. Peper	10-K	001-16179	10.5	8/5/2009
10.16†	Energy Partners, Ltd. 2009 Long Term Incentive Plan	S-8	333-162185	4.5	9/29/2009
10.17†	First Amendment to the Energy Partners, Ltd. 2009 Long Term Incentive Plan	10-K	001-16179	10.23	3/8/2012
10.18†	Form of 2009 Long Term Incentive Plan Option Award Agreement	8-K	001-16179	10.5	9/25/2009
10.19†	Form of 2009 Long Term Incentive Plan Restricted Stock Agreement	8-K	001-16179	10.6	9/25/2009
10.20†	Form of Indemnification Agreement for Directors	8-K	001-16179	10.1	11/24/2009
10.21†	Form of Indemnification Agreement for Officers	8-K	001-16179	10.2	11/24/2009
10.22†	Energy Partners, Ltd. Board Compensation Program	8-K	001-16179	10.1	11/12/2009
10.23†	Second Amended and Restated Stock and Deferral Plan for Non-Employee Directors, dated as of November 6, 2009	8-K	001-16179	10.2	11/12/2009
10.24†	Form of Director Deferred Share Agreement	8-K	001-16179	10.3	11/12/2009
10.25†	Employment Agreement dated as of February 1, 2012 between Energy Partners, Ltd. and John H. Peper	10-K	001-16179	10.24	3/8/2012
16.1	Letter from KPMG LLP dated July 1, 2010, addressed to the Securities and Exchange Commission	8-K	001-16179	16.1	7/1/2010

21.1	Subsidiaries of EPL Oil & Gas, Inc.	X
23.1	Consent of PricewaterhouseCoopers LLP.	X
23.2	Consent of Netherland, Sewell & Associates, Inc	X
23.3	Consent of W.D. Von Gonten & Co.	X
31.1	Certification of Principal Executive Officer of EPL Oil & Gas, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X
31.2	Certification of Principal Financial Officer of EPL Oil & Gas, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X
32.1	Section 1350 Certification of Principal Executive Officer of EPL Oil & Gas, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	X
32.2	Section 1350 Certification of Principal Financial Officer of EPL Oil & Gas, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	X
99.1	Report of Independent Petroleum Engineers (Netherland, Sewell & Associates, Inc) dated as of February 19, 2013	X
99.2	Report of Independent Petroleum Engineers (W.D. Von Gonten & Co.) dated as of February 19, 2013	X
101.SCH	XBRL Taxonomy Extension Schema Document	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	X

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