BLUE DOLPHIN ENERGY CO
Form 10-K
March 30, 2012
Table of Contents

Index to Financial Statements

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, 2011

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 No. 0-15905

BLUE DOLPHIN ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**73-1268729**
State or other jurisdiction of incorporation or organization	**(I.R.S. Employer Identification No.)**
801 Travis Street, Suite 2100 Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 568-4725

Registrant s telephone number, including area code

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

Title of each class	**Name of each exchange on which registered**
Common Stock, par value $0.01 per share	OTCQX

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

(Title of class)

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 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 (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	¨	Smaller Reporting Company	x

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

Aggregate market value of voting stock held by non-affiliates of the registrant as of June 30, 2011 was approximately $3,436,139 million based on the closing price of $3.01 per share on the NASDAQ Capital Market.

Number of shares of Common Stock outstanding as of March 30, 2012	10,533,070

DOCUMENTS INCORPORATED BY REFERENCE

Certain sections of the registrant s definitive proxy statement for its 2012 Annual Meeting of Stockholders, which is to be filed with the Securities and Exchange Commission pursuant to Regulation 14A, under the Securities and Exchange Act of 1934 within 120 days of the registrant s fiscal year ended December 31, 2011, are incorporated by reference in Part III of this report.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY

FORM 10-K REPORT INDEX

Table of Contents

Index to Financial Statements

CAUTIONARY STATEMENTS RELEVANT TO FORWARD-LOOKING INFORMATION

FOR THE PURPOSE OF SAFE HARBOR AS DEFINED IN THE

SECURITIES ACT OF 1933, AS AMENDED,

AND THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

This annual report on Form 10-K of Blue Dolphin Energy Company (referred to herein, with its predecessors and subsidiaries, as Blue Dolphin, we, us and our) contains forward-looking statements that are based on management s current expectations, estimates and projections related to Blue Dolphin s operations, the energy industry and other-related industries. Words such as expect, plan, believe, anticipate, project, estima similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond Blue Dolphin s control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. It is not possible to identify all of these risks, uncertainties or assumptions. Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: realization of anticipated benefits of acquired operations; volatility of refining margins; market acceptance of our refined products; performance of third-party operators; potential downtime for maintenance and repairs; environmental costs and liabilities associated with our operations; related party transactions and ownership; continued declines in throughput volumes and production rates from our U.S. Gulf of Mexico leasehold properties; our ability to offset revenue from one key customer; our ability to generate sufficient funds from operations or obtain financing from other sources; changing crude oil or natural gas prices; changes in reserve estimates; local and regional events that may negatively affect our assets; competition from larger companies; acquisition opportunities; operating hazards; insurance coverage limitations; retention and recruitment of key employees; compliance with environmental and other regulations; the effects of greenhouse gas emissions regulation; and the factors set forth under the heading Risk Factors in Item 1A of this report, as well as disclosures made under the caption Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this report. Other unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Blue Dolphin undertakes no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

PART I

ITEM 1. BUSINESS

On February 15 2012, we acquired Lazarus Energy, LLC, a Delaware limited liability company (LE) pursuant to a merger that has the potential to expand the size and scope of our business (the Acquisition). Except as otherwise noted, the description of our business contained in this Item 1 refers to the business of Blue Dolphin and its consolidated subsidiaries on a pre-acquisition basis. Further, the financial results contained in this report, which is for the twelve month period ended December 31, 2011, do not include any results from our crude oil and condensate processing operations which we acquired as part of the Acquisition.

The Company

Blue Dolphin, a Delaware corporation formed in 1986, manages the investments and conducts the operations of its wholly-owned subsidiaries. At December 31, 2011, Blue Dolphin operated two lines of business through its subsidiaries: (i) pipeline transportation services to producers/shippers and (ii) oil and gas exploration and production.

At December 31, 2011, Blue Dolphin s subsidiaries were as follows:

Blue Dolphin Pipe Line Company, a Delaware corporation (BDPL) (pipeline operations);

Blue Dolphin Petroleum Company, a Delaware corporation (BDPC) (exploration and production activities);

Blue Dolphin Exploration Company, a Delaware corporation (inactive);

Blue Dolphin Services Co., a Texas corporation (administrative services); and

Petroport, Inc., a Delaware corporation (inactive).

Our principal executive office is located at 801 Travis Street, Suite 2100, Houston, Texas, 77002, and our telephone number is (713) 568-4725. At December 31, 2011, we had five (5) full-time employees at locations in Freeport and Houston, Texas and regularly used the services of one (1) consultant. Our common stock, par value $0.01 per share (Common Stock) is publicly traded on the OTCQX U.S. Premier under the ticker symbol BDCO Our corporate website address is http://www.blue-dolphin.com.

Certain terms that are commonly used in the oil and gas industry, including terms that define our rights and obligations with respect to our interests in properties, are defined in the Glossary of Certain Oil and Gas Terms of this report.

Recent Developments

Acquisition of Lazarus Energy, LLC (LE). As previously reported, we entered into a Purchase and Sale Agreement (the PSA) with Lazarus Energy Holdings, LLC, a Delaware limited liability company (LEH) and LEH s wholly-owned subsidiaries to acquire one hundred percent (100%) of the issued and outstanding membership interests of LE, (the Acquisition). LE s primary asset is a 56-acre crude oil processing facility, located near Nixon, Texas (the Nixon Facility). On February 15, 2012, we consummated the Acquisition and issued, in reliance on the exemption provided by Section 4(2) of the Securities Act 8,393,560 shares of Common Stock, subject to anti-dilution adjustments, to LEH as consideration for LE (the Original BDEC Shares). Additionally, on February 21, 2012, pursuant to the anti-dilution provisions contained in the PSA, and in reliance on the exemption provided by Section 4(2) of the Securities Act, we issued 32,896 shares of Common Stock to LEH (the Anti-Dilution Shares and together with the Original BDEC Shares, the BDEC Shares) effective February 15, 2012. As a result of our issuance of the BDEC Shares, LEH currently owns eighty percent (80%) of our issued and outstanding Common Stock. The issuance of the BDEC Shares to LEH resulted in a change in control of Blue

4

Table of Contents

Index to Financial Statements

Dolphin. Further, pursuant to the terms of the PSA, the composition of Blue Dolphin s Board of Directors (the Board) and management changed. The Acquisition will be accounted for as a reverse acquisition in which LE is deemed to be the Acquirer and accounting predecessor and Blue Dolphin is deemed to be the Acquiree. Following the Acquisition, the combined company will continue to operate under the name Blue Dolphin Energy Company. See our Current Reports on Form 8-K filed with the Securities and Exchange Commission on July 22, 2011, February 2, 2012, February 21, 2012, February 28, 2012 and March 14, 2012, for more information on the Acquisition.

Management of Blue Dolphin s Assets. As part of LEH s assignment of the membership interests of LE, on February 15, 2012, Blue Dolphin, LE and LEH entered into a Management Agreement (the Management Agreement) pursuant to which LEH agreed to manage and operate the Nixon Facility and Blue Dolphin s other operations (collectively, the Services). Pursuant to the terms of the Management Agreement, LEH shall retain, as compensation for the Services, the right to receive (i) weekly payments based on revenues from the sale of diesel blend stocks processed by the Nixon Facility not to exceed $750,000 per month, (ii) reimbursement for certain accounting costs related to the preparation of LE s financial statements not to exceed $50,000 per month, (iii) $0.25 for each barrel processed at the Nixon Facility during the term of the Management Agreement, up to a maximum quantity of 10,000 barrels per day determined on a monthly basis, and (iv) $2.50 for each barrel processed at the Nixon Facility during the term of the Management Agreement, to the extent the quantity exceeds 10,000 barrels per day determined on a monthly basis. We further agreed to reimburse LEH at cost for all reasonable expenses incurred while performing the services. All compensation owed to LEH under the Management Agreement is to be paid to LEH within 30 days of the end of each calendar month. The Management Agreement expires upon the earliest to occur of (a) the date of the termination of the Joint Marketing Agreement between LE and a third party dated August 12, 2011, which has an initial term of three years and year-to-year renewals at the option of either party thereafter, (b) August 12, 2014, or (c) upon written notice of either party to the Management Agreement of a material breach of the Management Agreement by the other party. If the Management Agreement is renewed after the expiration of its initial term, then it will thereafter be reviewed on an annual basis by the Board and may be terminated if the Board determines that the Management Agreement is no longer in the best interest of Blue Dolphin.

LEH owns approximately eighty percent (80%) of our issued and outstanding Common Stock. Jonathan P. Carroll, our Chief Executive Officer, President, Assistant Treasurer and Secretary, and Tommy L. Byrd, our interim Chief Financial Officer, Treasurer and Assistant Secretary, are also a member and Chief Financial Officer, respectively, of LEH and, as a result may, under certain circumstances, have interests that differ from or conflict with our interests. Further, pursuant to the Management Agreement, LEH manages and operates the Nixon Facility and Blue Dolphin s other operations. As a result of their relationship with LEH, Messrs. Carroll and Byrd may experience conflicts of interest in the execution of their duties on behalf of Blue Dolphin including with respect to the Management Agreement. See Part I, Item 1A. Risk Factors of this report related to related party transactions.

Lazarus Energy Development, LLC (LED) Acquisition. Pursuant to the terms of the PSA, we had the option to acquire all of the issued and outstanding membership interests of LED, a Delaware limited liability company and a wholly-owned subsidiary of LEH. Among other assets, LED holds approximately 46 acres of real property adjacent to the Nixon Facility. On February 7, 2012, we paid LEH a refundable deposit of approximately $183,000 to exercise the option and as partial payment of the purchase price for LED. As part of the acquisition, we agreed to assume an LED loan in the amount of $1.5 million collateralized by the real property adjacent to the Nixon Facility. We expect to complete the acquisition of LED from LEH in the second quarter of 2012 for a total purchase price of approximately $1.68 million. See Part I, Item 1A. Risk Factors of this report related to acquisition opportunities, as well as Liquidity and Capital Resources under Part II, Item 7 of this report for additional information on how we plan to fund the acquisition of LED.

Table of Contents

Index to Financial Statements

Nasdaq Listing. On May 27, 2011, we received a letter from Nasdaq s Listing Qualifications Department (the Staff) notifying us that our stockholders equity had fallen below the $2.5 million minimum requirement for continued listing as set forth in Marketplace Rule 5550(b) (the Stockholders Equity Requirement). As a result of meeting the Stockholders Equity Requirement by a relatively slim margin related to a previous deficiency, a Nasdaq Hearings Panel (the Panel) placed us on a one year monitoring period (the Panel Monitoring Period). Receipt of Staff s May 27, 2011 letter created an additional deficiency for the Panel s consideration. We submitted a plan to meet the Stockholders Equity Requirement to the Panel on May 31, 2011. On June 9, 2011, we were notified by the Panel that our Common Stock would be delisted as a result of no longer meeting the Stockholders Equity Requirement. Although we filed an appeal of the Panel s decision to the Nasdaq Listing and Hearing Review Council (the Review Council), our Common Stock ceased trading on The Nasdaq Capital Market effective with the open of business on Monday, June 13, 2011, and began trading on the OTCQB Marketplace under the same ticker symbol immediately following suspension of trading on Nasdaq.

On July 21, 2011, we submitted a compliance plan to the Review Council based, in part, on the pending cash sale of certain of our assets to Sunoco Partners Marketing & Terminals L.P. (Sunoco), which would increase stockholders equity. On August 30, 2011, following the consummation of the transaction with Sunoco, we received notification from the Panel, pursuant to instructions received from the Review Council, that: (i) our Common Stock would resume trading on the Nasdaq Capital Market effective September 1, 2011 before the open of the markets and (ii) our continued compliance with the Stockholders Equity Requirement was subject to a Panel Monitoring Period.

On January 3, 2012, we were notified by Staff that we failed to hold an annual meeting of shareholders, solicit proxies and provide proxy statements to Nasdaq as set forth in Marketplace Rule 5620(a) and 5620(b) (the Annual Meeting Requirement). As we were under a Panel Monitoring Period, receipt of Staff s January 3, 2012 letter created an additional deficiency for the Panel s consideration. On January 18, 2012, we submitted a compliance plan to the Panel based on our then scheduled 2011 Annual Meeting of Stockholders (the Annual Meeting) to be held on January 27, 2012. The definitive proxy statement for the Annual Meeting was filed with the Securities and Exchange Commission (the SEC) on December 28, 2011. The Annual Meeting was delayed beyond the 2011 calendar year as a result of the Acquisition, certain parameters of which required stockholder approval.

On December 8, 2011, the Staff determined that the Acquisition qualified as a Business Combination and that, pursuant to Marketplace Rule 5110(a), we would have to apply and be approved for initial listing of our Common Stock on the Nasdaq Capital Market on a post-Acquisition basis (the New Nasdaq Listing Application). If closing of the Acquisition occurred prior to us receiving approval of the New Nasdaq Listing Application, our Common Stock was subject to delisting pursuant to Marketplace Rule 5110(a). We submitted the New Nasdaq Listing Application to the Staff on December 13, 2011 and have worked with the Staff to provide additional information as requested. On February 15, 2012, we consummated the Acquisition. On February 24, 2012, we received notification that the Panel had determined to delist our Common Stock from the Nasdaq Capital Market and suspend trading in the shares effective at the open of business on February 28, 2012. Simultaneous with the Nasdaq delisting, our Common Stock began trading on the OTCQX U.S. Premier tier of the OTC Markets under the ticker symbol BDCO . We plan to continue to file with the SEC any and all reports as may be required under the Securities and Exchange Act of 1934, as amended (the Exchange Act) following the delisting. Although we are attempting to relist our Common Stock on the Nasdaq Capital Market, there can be no assurance that the Staff will approve the New Nasdaq Listing Application.

Disposition of Pipeline Assets. On August 3, 2011, BDPL, a wholly-owned subsidiary of Blue Dolphin completed the sale of its eighty-three and one-third percent (83 $^{1}/3$%) interest in the Buccaneer Pipeline to Sunoco for net proceeds of approximately $3.6 million in cash. The Buccaneer Pipeline is located onshore in Brazoria County, Texas. Assets in the sale also included above ground storage tanks, a barge loading terminal, a pumping station and related equipment. As a result of the sale, Blue Dolphin no longer handles the onshore transportation and storage of oil.

6

Table of Contents

Index to Financial Statements

Crude Oil and Condensate Processing

The standard refining process is complex and involves numerous stages to create final products. By contrast, the Nixon Facility s operations are only involved in the first stage of the refining process. The Nixon Facility, which has an operating capacity of approximately 15,000 barrels of oil per day, consists of tankage, a distillation unit, recovery facilities and the necessary utility systems. As a topping unit, the Nixon Facility separates input crude oil and condensate into diesel and jet fuel for sale into nearby markets, as well as naphtha and atmospheric gasoil for sale to nearby refineries for further processing. Input crude oil and condensate is currently purchased on the spot market (month to month) and delivered by truck. However, the facility also has the ability to receive crude oil and condensate via pipeline. Refined products are currently sold and delivered by truck. The Nixon Facility s assets are held by LE. Financial results contained in this report do not include those of our Nixon Facility s operations.

Pipeline Operations

We gather and transport oil and natural gas for producers/shippers operating offshore in the vicinity of our pipelines in the U.S. Gulf of Mexico and charge a fee based on anticipated throughput volumes. We handle the sale of gas through a chemical plant complex and intrastate pipeline system tie-in. All of our pipeline assets are held by and the business conducted by BDPL. Unless otherwise stated herein, all gas liquid volumes transported are attributable to production from third-party producers/shippers.

Pipeline Assets. The following provides a summary of our pipeline segments:

Pipeline Segment	Market	Ownership	Miles of Pipeline	Capacity (MMcf/d)	Average Throughput (MMcf/d)		
					2011	2010	2009
BDPS	U.S. Gulf of Mexico	83.3%	38	180	4.4	13.7	15.5
GA 350	U.S. Gulf of Mexico	83.3%	13	65	13.6	17.4	19.0
Omega	U.S. Gulf of Mexico	83.3%	18	110			

Blue Dolphin Pipeline System (BDPS) The BDPS spans approximately 38 miles and runs from Galveston Area Block 288 offshore to our onshore facilities and the Dow Chemical Plant Complex in Freeport, Texas. The BDPS has an aggregate capacity of approximately 180 MMcf of gas and 7,000 Bbls of crude oil and condensate per day. The BDPS is currently transporting an aggregate of approximately 3 MMcf of gas per day, which represents 1% of throughput capacity.

The BDPS includes: (i) approximately 188 acres of land in Brazoria County, Texas where the Blue Dolphin Pipeline comes ashore and where the BDPS onshore facilities, pipeline easements and rights-of-way are located, (ii) an offshore platform and (iii) the Blue Dolphin Pipeline. The BDPS gathers and transports oil and gas from various offshore fields in the Galveston Area of the U.S. Gulf of Mexico to our onshore facilities located in Freeport, Texas. The oil is processed, stored and sold by a third-party. The gas is transported to the Dow Chemical Plant Complex and a major intrastate pipeline system with further downstream tie-ins to other intrastate and interstate pipeline systems and end users.

Galveston Area Block 350 Pipeline (the GA 350) The GA 350 is an 8-inch, 13 mile offshore pipeline extending from Galveston Area Block 350 to an interconnect with a transmission pipeline in Galveston Area Block 391 located approximately 14 miles south of the Blue Dolphin Pipeline. Current system capacity on the GA 350 is 65 MMcf of gas per day. The GA 350 is currently transporting an aggregate of approximately 9 MMcf of gas per day, which represents 14% of throughput capacity.

Table of Contents

Index to Financial Statements

Omega Pipeline (the Omega) The Omega originates in the High Island Area, East Addition Block A-173 and extends to West Cameron Block 342, where it was previously connected to the High Island Offshore System. The Omega is currently inactive. Reactivation of the Omega is dependent upon future drilling activity in the vicinity and successfully attracting producer/shippers to the system.

Exploration and Production

Our oil and gas exploration and production activities include leasehold interests in properties located in the U.S. Gulf of Mexico and the North Sumatra Basin offshore Indonesia. Our leasehold interests, which are held in and the operations conducted by BDPC, are subject to royalty and overriding royalty interests. We evaluate and manage oil and gas properties giving consideration to geography, reserve life and hydrocarbon mix based on seismic and other data.

During the year ended December 31, 2011, our unamortized cost exceeded the present value of estimated future net revenues, and we recorded an impairment to our U.S. Gulf of Mexico oil and gas properties of $252,706. Although our U.S. Gulf of Mexico oil and gas properties may continue to operate over the next twelve to eighteen months, we expect the operating costs to exceed gross revenues based on current reserves and net cash flow estimates making these properties uneconomic.

Exploration and Production Assets. The following provides a summary of our oil and gas properties:

Field	Operator	Interest
Indonesia:		
North Sumatra Basin-Langsa Field	Blue Sky Langsa, Ltd.	7% WI, 5.20625% NRI (+ reversion)
U.S. Gulf of Mexico:		
High Island Block 115	Rooster Petroleum, LLC	2.5% WI, 2.008% NRI
Galveston Area Block 321	Black Elk Energy Offshore Operations LLC	0.5% ORRI
High Island Block 37	Hilcorp Energy Company	2.88% WI, 2.246% NRI

North Sumatra Basin-Langsa Field Located offshore Indonesia, the North Sumatra Basin-Langsa Field covers approximately 77 square kilometers and contains two oil fields the L Field and the H Field. Four wells have been completed in each field. All four wells in the L Field are currently shut-in. In the H Field, two of the wells have been plugged and abandoned, one is suspended and one (the H-4 Well) is currently producing. The wells are completed subsea in 325 feet of water and productive via flexible pipelines to a Floating Production Storage and Offloading barge. The H-4 Well is currently producing approximately 370 barrels of oil per day.

High Island Block 115 High Island Block 115 is located approximately 30 miles southeast of Bolivar Peninsula in an average water depth of approximately 38 feet. The block contains one active well, the B-1 ST2 Well. The B-1 ST2 Well is currently producing approximately 2 MMcf of gas per day.

Galveston Area Block 321 Galveston Area Block 321 is located approximately 32 miles southeast of Galveston in an average water depth of approximately 66 feet. The block contains one active well, the A-4 Well. The A-4 Well is currently producing approximately 2 MMcf of gas per day.

High Island Block 37 High Island Block 37 is located approximately 15 miles south of Sabine Pass in an average water depth of approximately 36 feet. The block contains no active wells.

Table of Contents

Index to Financial Statements

At December 31, 2011, there were no active drilling or development activities associated with our exploration and production assets.

Productive Wells and Acreage. The following table sets forth our ownership interest at December 31, 2011, in productive oil and natural wells in the areas indicated. Wells are classified as oil or natural gas according to their predominant production stream. Gross wells reflect the total number of producing wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working or royalty interest. Productive wells consist of producing wells and wells capable of production.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Indonesia						
Working Interest	1.0	0.1			1.0	0.1
U.S. Gulf of Mexico						
Working Interest			2.0	0.1	2.0	0.1
Overriding Royalty Interest			1.0		1.0	
	1.0	0.1	3.0	0.1	4.0	0.2

The following table sets forth the approximate developed and undeveloped acreage that we held as leasehold interest at December 31, 2011. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether or not such acreage contains proved reserves.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Indonesia	3,108	218	15,919	1,114	19,027	1,332
U.S. Gulf of Mexico	17,280	264			17,280	264
	20,388	482	15,919	1,114	36,307	1,596

Reserve Categories. Reserves are classified as either proved, probable or possible according to the degree of certainty associated with the estimates. This report contains no estimates of probable or possible reserves. Proved reserves as reported herein are further sub-categorized as either developed or undeveloped depending on their development and production status. The quantities of proved developed and undeveloped oil and gas reserves presented herein include only those amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under existing economic and operating conditions. Therefore, proved developed and undeveloped reserves are limited to those quantities that are believed to be recoverable at prices and costs, and under regulatory practices and technology, existing at the time of the estimate. Accordingly, changes in oil and gas prices, operation and development costs, regulations, technology, future production and other factors, many of which are beyond our control, could significantly affect the estimates of proved developed and undeveloped reserves and the discounted present value of future net revenue attributable thereto.

Estimates of production and future net revenue cannot be expected to represent accurately the actual production or revenue that may be recognized with respect to oil and gas properties or the actual present market value of such properties. See Note (11), Supplemental Oil and Gas Information (Unaudited), in the Notes to Consolidated Financial Statements for further information concerning our proved developed and undeveloped reserves, changes in proved developed and undeveloped reserves, estimated future net revenue and costs incurred in our oil and gas activities and the discounted present value of estimated future net revenue from our proved developed and undeveloped reserves.

Table of Contents

Index to Financial Statements

Reserves Basis of Presentation. Our proved reserves and future net cash flows estimates for oil and natural gas were prepared by independent petroleum engineering consulting firms registered with the Society of Petroleum Engineers, as follows:

Indonesia	U.S. Gulf of Mexico
Stephen A. Lieberman, P.E.	Richard R. Lonquist, P.E.
President	President
American Energy Advisors, Inc.	Lonquist & Co., LLC

Mr. Lieberman has 37 years of experience in petroleum engineering, petroleum studies and evaluations. He attended Colorado School of Mines and Pennsylvania State University and earned a Bachelor of Science Degree in Petroleum and Natural Gas Engineering. He is a registered and active member of the Society of Petroleum Engineers.

Mr. Lonquist has more than 23 years of experience in petroleum engineering, underground storage engineering, mining engineering and financial consulting services for energy production, transmission and energy storage companies, banks, trusts and institutional investors. He earned a Bachelor of Science in Petroleum Engineering from Texas A&M University. He is a registered and active member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Evaluations done by Messrs. Lieberman and Lonquist were done in accordance with the generally accepted petroleum engineering and evaluation principles and the most recent definitions and guidelines established by the SEC. All reserve definitions contained herein are in accordance with the SEC s Rule 4-10(a)(1)-(32) of Regulation S-X.

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

Estimated Proved Reserves and Future Net Cash Flows. The following table presents the estimates of proved developed and undeveloped reserves (as hereinafter defined) and the discounted present value of future net revenue or expenses from proved developed and undeveloped reserves after income taxes to our net interest in oil and gas properties as of December 31, 2011. The discounted present value of future net revenue or expenses is calculated using the SEC Method (defined below) and is not intended to represent the current market value of the oil and gas reserves we own.

Proved Natural Gas and Oil Reserves

as of December 31, 2011

	Net Oil Reserves (Mbbls)	Net Gas Reserves (MMcf)	Discounted Present Value of Future Net Cash Inflows (Outflows) (1) (in thousands)
Proved Developed			
North Sumatra Basin-Langsa Field	31.6		$ 1,339
High Island Block 115		13.0	1
Galveston Area Block 321			
High Island Block 37			(31)
Total Proved Developed Reserves	31.6	13.0	$ 1,309
Proved Undeveloped			
North Sumatra Basin-Langsa Field	151.0		$ 8,018
High Island Block 115			
Galveston Area Block 321			
High Island Block 37			
Total Proved Undeveloped Reserves	151.0		$ 8,018

(1) The estimated present value of future net cash outflows from our proved reserves has been determined by using domestic prices of $96.04 per barrel of oil and $4.18 per Mcf of gas and an international price of $114.95 per barrel of oil, representing the 12-month average price for oil and natural gas, respectively, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period to the end of the reporting period and discounted at a 10% annual rate in accordance with requirements for reporting oil and gas reserves pursuant to regulations promulgated by the SEC (the SEC Method).

We had total estimated proved undeveloped reserves of 175.3 Mbbls and 104.0 Mbbls as of December 31, 2011 and 2010, respectively. During 2011, we did not convert any proved undeveloped reserves to proved developed reserves. At December 31, 2011, no material amounts of proved undeveloped reserves have remained undeveloped for five years or more after they were initially disclosed as proved undeveloped reserves.

Internal Controls over Reserve Estimates. We engaged independent petroleum engineering consulting firms to prepare our final reserve estimates and have relied on their expertise to ensure that our reserve estimates were prepared in compliance with SEC guidelines and with generally accepted petroleum engineering principles. The technical persons primarily responsible for the preparation of the reserve reports have been identified herein. We provided the independent petroleum engineering consulting firms with estimate preparation material such as property interests, production, current operation costs, current production prices and other information. This information was reviewed by our Principal Executive Officer and Principal Financial Officer to ensure accuracy and completeness of the data prior to submission to the petroleum engineering consulting firms.

Capital Expenditures for Proved Reserves. The following table presents information regarding the costs we expect to incur in activities associated with our proved reserves. These expenditures represent costs associated with the plugging and abandonment of wells. The information regarding proved reserves summarized in the preceding table assumes the following estimated undiscounted capital expenditures in the years indicated (amounts in thousands).

Estimated Undiscounted Capital Expenditures

Associated with Plugging and Abandonment of Wells

	$0000	$0000	$0000	$0000	$0000
	Years Ending December 31,				
	2012	2013	2014	2015	2016
North Sumatra Basin-Langsa Field					
High Island Block 115		$ 39			
Galveston Area Block 321					
High Island Block 37	$ 68				
High Island A-7	$ 135				

Remainder of Page Intentionally Left Blank

Production, Price and Cost Data. The following table presents information regarding production volumes and revenue, average sales prices and costs (after deduction of royalties and interests of others) with respect to crude oil, condensate and natural gas attributable to our interests for each of the periods indicated.

Net Production, Price and Cost Data

	Years Ended December 31,					
	2011		2010		2009	
	Indonesia	U.S. Gulf of Mexico	Indonesia	U.S. Gulf of Mexico	Indonesia	U.S. Gulf of Mexico
Crude Oil and Condensate:						
Production (Bbls)	10,254	272	8,154	250		250
Revenue	$ 1,222,378	$ 25,991	$ 720,348	$ 20,377	$	$ 17,401
Average production per day (Bbls) (*)	28.1	0.7	22.3	0.7		0.7
Average sales price per Bbl	$ 119.21	$ 95.56	$ 88.34	$ 81.51	$	$ 69.60
Natural Gas:						
Production (Mcf)		25,454		31,654		33,630
Revenue	$	$ 94,349	$	$ 121,960	$	$ 108,576
Average production per day (Mcf) (*)		69.7		86.7		92.1
Average sales price per Mcf	$	$ 3.71	$	$ 3.85	$	$ 3.23
Production Costs (**):						
Per Mcfe:	$ 17.85	$ 2.80	$ 12.29	$ 2.19	$	$ 2.71

(*) Average production is based on a 365 day year.

(**) Production costs, exclusive of work-over costs, are costs incurred to operate and maintain wells and equipment and to pay production taxes.

Drilling, Exploration and Development Activity. During 2011, there were no wells drilled or any other exploratory or development activities conducted.

Other Assets

We own a non-hazardous Class I salt water disposal well located near the town of Mermentau, Jefferson Davis Parish, Louisiana. The well is not currently operational.

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

Customers

Revenue from customers exceeding 10% of our total revenue for 2011 and 2010 were as follows:

	Natural Gas and Oil Sales	Pipeline Operations	Customer Total	% of Total Revenue
Year Ended December 31, 2011:				
Blue Sky Langsa, Ltd.	$ 1,222,378	$	$ 1,222,378	54%
Year Ended December 31, 2010:				
Blue Sky Langsa, Ltd.	$ 720,348	$	$ 720,348	26%
W&T Offshore	$	$ 557,419	$ 557,419	20%
Black Elk Energy Offshore Operations, LLC	$ 48,194	$ 296,921	$ 345,115	12%

Markets & Competition

Petroleum industry operations and profitability are influenced by many factors. Prices for crude oil, natural gas, petroleum products and petrochemicals are generally determined by supply and demand. Demand for crude oil and its products and for natural gas is largely driven by the conditions of local, national and global economies, although weather patterns and taxation relative to other energy sources also play a significant part. Laws and governmental policies, particularly in the areas of taxation, energy and the environment affect where and how companies conduct their operations and formulate their products and, in some cases, limit their profits directly.

In view of the many uncertainties that affect petroleum industry operations, it is impossible to accurately predict the price and marketability of our oil and natural gas production or the rates charged for our transportation services. Currently, our oil production is sold at market prices at the time of lifting and our natural gas production is sold at market prices at the time of transmission to a major intrastate pipeline.

Intellectual Property

We rely on intellectual property laws to protect our brand, as well as those of our subsidiaries. Blue Dolphin is a registered trademark in the U.S. in name and logo form. Petroport is a registered trademark in the U.S. in name form. In addition, www.blue-dolphin.com is a registered domain name. Previously held patents in Belgium, Denmark, France, Germany, Great Britain, Greece, Israel, Italy, the Netherlands and Spain related to an offshore storage facility and terminal were abandoned in 2010.

Governmental Regulation

We are subject to numerous environmental, legal and regulatory requirements related to our domestic and foreign operations, which can have a significant impact upon our overall operations.

Domestic. In the United States, laws and regulations under which our operations are subject include, among others:

Federal Regulation of Natural Gas Transportation. Historically, the transportation and sales for resale of natural gas in interstate commerce have been regulated by the Natural Gas Act (NGA), the Natural Gas Policy Act (NGPA) and the rules and regulations promulgated by the Federal Energy Regulatory Commission (FERC). In the past, the federal government has regulated the prices at which gas could be sold. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining NGA and NGPA price and non-price controls affecting producer sales of gas, effective January 1, 1993. The Energy Policy Act of 2005 (the 2005 Energy Act) did not alter our non-FERC-jurisdictional status, but the 2005 Energy Act greatly expanded FERC s enforcement authority, including enforcement against market manipulation in connection with FERC-jurisdictional transactions. Under the 2005 Energy Act, FERC has undertaken vigorous enforcement actions against a number of entities, including those not subject to direct FERC regulation, and, in an effort to increase transparency in natural gas markets, has taken steps to require reporting by interstate, major non-interstate and potentially certain intrastate pipelines. Additionally, energy pricing has attracted renewed political interest. Therefore Congress could reenact regulatory controls in the future. The rates, terms and conditions applicable to interstate transportation of gas by pipelines are regulated by FERC under the NGA, as well as under Section 311 of the NGPA. FERC has extended certain reporting requirements to otherwise non-jurisdictional intrastate pipelines and to major non-interstate natural gas pipelines, including non-jurisdictional gathering lines that deliver more than 50 million MMBtu per year, a cutoff that excludes us from this requirement. In February 2007, FERC issued a policy order acknowledging its lack of jurisdiction over offshore gathering, but stated that FERC would intervene in the event that interstate pipelines with affiliated offshore gathering lines engage in anti-competitive behavior, such as conditioning access to interstate pipeline service upon use of the affiliated gathering line.

All of our pipelines located offshore in federal waters are subject to the requirements of the Outer Continental Shelf Lands Act (OCSLA), which was administered by the Bureau of Ocean Energy Management, Regulation and Enforcement and, after October 1, 2011, its successors, the Bureau of Ocean Energy Management (the BOEM) and the Bureau of Safety and Environmental Enforcement (the BSEE). Together with the FERC, the BOEM and BSEE require that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its NGA jurisdiction. Therefore, we do not believe that any FERC, BOEM or BSEE action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

Aside from the OCSLA requirements and federal safety and operational regulations, regulation of gas gathering activities is primarily a matter of state oversight. Regulation of gathering activities in Texas includes various transportation, safety, environmental and non-discriminatory purchase/transport requirements.

Federal Regulation of Oil Pipelines. Our operation of the Buccaneer Pipeline previously subjected us to a variety of regulations promulgated by FERC and imposed on all oil pipelines pursuant to federal law. The Buccaneer Pipeline was sold to Sunoco in August 2011 and the associated FERC tariffs were adopted by Sunoco per its adoption notice FERC no. 191.0.0 issued August 25, 2011.

Safety and Operational Regulations. Our operations are generally subject to safety and operational regulations administered by the BSEE, the Department of Transportation, the Coast Guard, FERC and/or various state agencies. The recently enacted Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 requires that the Secretary of Transportation develop several new regulatory programs to enhance pipeline safety over the coming years. In addition, the OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms and structures. Violations of lease conditions or regulations issued pursuant to the OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities can result from either governmental or private prosecution. Currently, we believe that we are in material compliance with the various safety and operational regulations that we are subject to. However, as safety and operational regulations are frequently changed, we are unable to predict the future effect changes in these regulations will have on our operations, if any.

Federal Oil and Gas Leases. Our U.S. Gulf of Mexico exploration and production operations are currently located on federal oil and gas leases in the OCS, which are administered by BOEM. Such leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed BOEM regulations and orders pursuant to the OCSLA that are subject to interpretation and change by

Table of Contents

Index to Financial Statements

BOEM. For offshore operations, lessees must obtain BOEM approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies, such as the U.S. Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency (the EPA), lessees must obtain a permit from BOEM prior to the commencement of drilling. BOEM has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. To cover the various obligations of lessees on the OCS, BOEM generally requires that lessees have substantial net worth or post bonds or other acceptable assurance that such obligations will be met. The cost of such bonds or other surety can be substantial, and there is no assurance that bonds or other surety can be obtained in all cases. We are currently in compliance with the bonding requirements of BOEM. Under some circumstances, BOEM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations.

With respect to our operations that are conducted on offshore federal leases, liability may generally be imposed under OCSLA for clean-up costs and pollution damages resulting from such operations, generally excluding damages caused by acts of war or the negligence of third parties. Under certain circumstances, including but not limited to conditions deemed a threat or harm to the environment, BOEM may also require any of our operations on federal leases to be suspended or terminated in the affected area. Furthermore, BOEM generally requires that offshore facilities be dismantled and removed within one year following production cessation or lease expiration.

Environmental Regulation. Our activities with respect to: (i) exploration, development and production of oil and natural gas and (ii) operation and construction of pipelines, plants and other facilities for the transportation of oil and natural gas are subject to stringent environmental regulation by local, state and federal authorities, including the EPA. Such regulation has increased the cost of planning, designing, drilling, operating and, in some instances, abandoning wells and related equipment. Similarly, such regulation has also increased the cost of design, construction and operation of crude oil and natural gas pipelines and processing facilities. Although we believe that compliance with existing environmental regulations will not have a material adverse effect on our operations or earnings, there can be no assurance that significant costs and liabilities, including civil and criminal penalties, will not be incurred. Moreover, future developments, such as stricter environmental laws and regulations or claims for personal injury or property damage resulting from our operations, could result in substantial costs and liabilities. In the event significant changes in environmental requirements occur, we may be required to expend amounts that are material relative to our total capital structure.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) imposes liability, without regard to fault or the legality of the original conduct, on parties the statute defines as responsible for the release or threatened release of a hazardous substance into the environment. Responsible parties, which include the present owner or operator of a site where the release occurred, the owner or operator of the site at the time of disposal of the hazardous substance, and persons that disposed of or arranged for the disposal of a hazardous substance, are liable for response and remediation costs and for damages to natural resources. Petroleum and natural gas are excluded from the definition of hazardous substances; however, this exclusion does not apply to all materials used in our operations. State statutes impose similar liability. At this time, neither we nor any of our predecessors have been designated as a potentially responsible party under CERCLA or similar state statute.

The federal Resource Conservation and Recovery Act (RCRA) and its state counterparts regulate solid and hazardous wastes and impose civil and criminal penalties for improper handling and disposal of such wastes. EPA and various state agencies have promulgated regulations that limit the disposal options for such wastes. Certain wastes generated by our oil and gas operations are currently exempt from regulation as hazardous wastes, but in the future could be designated as hazardous wastes under RCRA or other applicable statutes and therefore may become subject to more rigorous and costly requirements.

Table of Contents

Index to Financial Statements

We currently own or lease, or have in the past owned or leased, various properties used for the exploration and production of oil and gas or used to store and maintain equipment regularly used in these operations. Although our past operating and disposal practices at these properties were standard for the industry at the time, hydrocarbons or other substances may have been disposed of or released on or under these properties or on or under other locations. In addition, many of these properties have been operated by third parties whose waste handling activities were not under our control. These properties and any waste disposed thereon may be subject to CERCLA, RCRA, and state laws which could require us to remove or remediate wastes and other contamination or to perform remedial plugging operations to prevent future contamination.

The Oil Pollution Act of 1990 (OPA) and regulations promulgated thereunder include a variety of requirements related to the prevention of oil spills and impose liability for damages resulting from such spills. OPA imposes liability on owners and operators of onshore and offshore facilities and pipelines for removal costs and certain public and private damages arising from a spill. OPA establishes a liability limit for onshore facilities of $350 million and offshore facilities of $75 million plus all clean-up costs. OPA establishes lesser liability limits for vessels depending upon their size. A party cannot take advantage of the liability limits if the spill is caused by gross negligence or willful misconduct or resulted from a violation of federal safety, construction or operating regulations. If a party fails to report a spill or cooperate in the clean-up, liability limits do not apply. OPA imposes ongoing requirements on responsible parties, including proof of financial responsibility for potential spills. The amount of financial responsibility required depends upon a variety of factors, including the facility or vessel type, size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, discharge history, worst-case spill potential and other considerations. We believe we have established adequate financial responsibility. While our financial responsibility requirements under OPA may be amended to impose additional costs, we do not expect the impact of such a change to be any more burdensome on us than on others similarly situated.

The Clean Air Act and state air quality laws and regulations contain provisions that impose pollution control requirements on emissions to the air and require permits for construction and operation of certain emissions sources, including sources located offshore. We may be required to incur capital expenditures for air pollution control equipment in connection with maintaining or obtaining construction and operating permits and approvals addressing emission-related issues, although we do not expect to be materially adversely affected by such expenditures.

The Clean Water Act (CWA) regulates the discharge of pollutants to waters of the United States and imposes permit requirements on such discharges, including discharges to wetlands. Federal regulations under the CWA and OPA require certain owners or operators of facilities that store or otherwise handle oil, to prepare and implement spill prevention, control and countermeasure plans and facility response plans relating to the possible discharge of oil into surface waters. With respect to certain of our operations, we are required to prepare and comply with such plans and to obtain and comply with permits. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide varying civil and criminal penalties and liabilities for the spills to both surface and ground waters. We believe we are in substantial compliance with the requirements of the CWA, OPA and state laws, and that any non-compliance would not have a material adverse effect on us.

Various federal and state programs regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act was passed to preserve and, where possible, restore the natural resources of the coastal zone of the United States and to provide for federal grants for state management programs that regulate land use, water use and coastal development. Under the Louisiana Coastal Zone Management Program, coastal use permits are required for certain activities, even if the activity only partially infringes upon the coastal zone. Among other things, projects involving use of state lands and water bottoms, dredge or fill activities that intersect with more than one body of water, mineral activities, including the exploration and production of oil and gas, and pipelines for the gathering, transportation or transmission of oil, gas and other minerals require such permits. General permits, which entail a reduced administrative burden, are available for a number of routine oil and gas activities. The Texas Coastal Coordination Act (TCCA) establishes the Texas Coastal Management Program that applies in the nineteen Texas counties that border the U.S. Gulf of Mexico and its tidal bays. The TCCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. These coastal programs may affect agency permitting of our facilities.

Legislation and Rulemaking. In October 1996, the U.S. Congress enacted the Coast Guard Authorization Act of 1996 (P.L. 104-324), which amended the OPA to establish requirements for evidence of financial responsibility for certain offshore facilities. The evidence of financial responsibility amount required is $35 million for certain types of offshore facilities located seaward of the seaward boundary of a state, including properties used for oil transportation. We currently maintain the statutory $35 million coverage.

Federal and state legislation and regulations have been proposed that, if enacted or promulgated, could significantly affect operations in the oil and gas industry. It is not possible to predict which of the proposals, if any, will be adopted and what effect, if any, they would have on our operations. However, changes in various federal, state and local laws and regulations covering the discharge of materials into the environment, occupational health and safety issues or otherwise relating to the protection of public health and the environment, may affect our operations and costs to do business. Historically, the trend in such laws and regulations has been to place more restrictions and limitations on activities that may impact the general or work environment, such as emissions of pollutants, generation and disposal of wastes and use and handling of chemical substances, the cost of compliance of which has continued to increase. It is not possible to predict which of the proposed federal, state and local laws and regulations, if any, will be adopted and the impact such changes may have on our operations and capital structure. We will adopt measures that maintain our compliance.

Foreign. In Indonesia, our operations are subject to the government acts, laws and regulations of the Republic of Indonesia, as well as to any international treaties or conventions to which the Republic of Indonesia is a signatory.

Employees

At December 31, 2011, we had five (5) full-time employees and regularly used the services of one (1) consultant. Our employees, along with the expertise provided by our engineering consultant, manage our ongoing administrative, business development and marketing operations. From time to time, we use third parties to assist with major maintenance, engineering and construction projects and activities.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data.

Available Information

We make available, free of charge on or through our website (http://www.blue-dolphin.com), our annual, quarterly and current reports, and any amendments to those reports, as soon as practical after these reports are filed with the SEC. The public may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street, Northeast, Washington, D.C. 20549, on official business days during the hours of 10:00 a.m. to 3:00 p.m. The public may obtain information on the operation of the Public Reference Room by calling the SEC at (800) SEC-0330. The SEC maintains an Internet site (http://www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

Table of Contents

Index to Financial Statements

Information about each of our directors, as well as each of the Board s standing committee charters, our corporate governance guidelines and our code of business conduct are also available, free of charge, through our website. Information contained on our website is not part of this report.

Glossary of Certain Oil and Gas Terms

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry.

Back-in After Payout Interest. A contractual right of a non-participating partner to participate in a well or wells after the wells have produced enough for the participating partners to recover their capital costs of drilling, completing and operating the wells.

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

Bcf. One billion cubic feet of gas.

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

Condensate. Hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced; a mixture of pentanes and higher hydrocarbons.

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

Exploratory Well. A well drilled to find and produce gas or oil in an unproved area, to find a new reservoir in a field previously found to be productive of gas or oil in another reservoir or to extend a known reservoir.

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

Leasehold Interest. The interest of a lessee under an oil and gas lease.

Mbbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of gas.

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

MMbtu. One million British Thermal Units.

MMcf. One million cubic feet of gas.

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

Net Revenue Interest. The percentage of production to which the owner of a working interest is entitled.

Non-operating Working Interest. A working interest, or a fraction of a working interest, in a lease where the owner is not the operator of the lease.

Table of Contents

Index to Financial Statements

Overriding Royalty Interest. An interest in oil and gas produced at the surface, free of the expense of production that is in addition to the usual royalty interest reserved to the lessor in an oil and gas lease.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of oil, gas or both.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved developed reserves are further categorized into two sub-categories proved developed producing reserves and proved developed non-producing reserves.

Proved Developed Producing. Reserves sub-categorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate.

Proved Developed Non-producing. Reserves sub-categorized as non-producing, which include shut-in and behind pipe reserves. Shut-in reserves are expected to be recovered from: (i) completion intervals which are open at the time of the estimate but which have not started producing, (ii) wells which were shut-in awaiting pipeline connections or as a result of a market interruption or (iii) wells not capable of producing for mechanical reasons.

Proved Reserves. The estimated quantities of oil, gas 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 reserves are further categorized into two sub-categories proved developed and proved undeveloped depending on their development and production status.

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells or from existing wells where a relatively significant expenditure is required for recompletion.

Reversionary Interest. A form of ownership interest in property that reverts back to the transferor after expiration of an intervening income interest or the occurrence of another triggering event.

Royalty Interest. An interest in a gas and oil property entitling the owner to a share of gas and oil production free of any of the operational costs associated with the production.

Undivided Interest. A form of ownership interest in which more than one person concurrently owns an interest in the same oil and gas lease or pipeline.

Working Interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production after the corresponding percentage of operational costs and royalties are paid.

ITEM 1A. RISK FACTORS

There are numerous factors that affect our business and operating results, many of which are beyond our control. The following is a description of significant factors that might cause our future operating results to differ materially from those currently expected. The risks described below are not the only risks we face. Additional risks and uncertainties not specified herein, not currently known to us or currently deemed to be immaterial also may materially adversely affect our business, financial position, operating results and/or cash flows.

Table of Contents

Index to Financial Statements

Risks Related to our Business

The success of our acquisition of LE will depend on our ability to realize the anticipated benefits from integrating LE s business into our operations.

We may fail to realize the anticipated benefits from this integration on a timely basis, or at all, for a variety of reasons, including the following:

- difficulties expanding in new markets or geographies where we have no or limited direct prior experience;
- failure to identify or assess the magnitude of certain liabilities we assumed in the acquisition, which could result in unexpected litigation or regulatory exposure, unfavorable accounting treatment, unexpected increases in taxes due, a loss of anticipated tax benefits or other adverse effects on our business, operating results or financial condition;
- difficulties or delays in incorporating acquired technologies or integrating overall operations and business systems while maintaining uniform standards, controls, processes and policies;
- failure to successfully manage relationships with our combined supplier and customer base; and
- difficulties in modifying LE s existing accounting and internal control systems to comply with Section 404 of the Sarbanes-Oxley Act of 2002, to which LE is not currently subject, which could adversely impact the effectiveness of internal control over financial reporting for the combined company.

Refining margins are volatile, and a reduction in anticipated refining margins will adversely affect the amount of cash we will have available for working capital.

Historically, refining margins have been volatile, and they are likely to continue to be volatile in the future. Our financial results are primarily affected by the relationship, or margin, between our specialty products prices and the prices for crude oil. The cost to acquire crude oil and the price at which we can ultimately sell our refined products depend upon numerous factors beyond our control.

The prices at which we sell specialty products are strongly influenced by the commodity price of crude oil. If crude oil prices increase, our specialty products segment margins will fall unless we are able to pass along these price increases to our wholesale customers. Increases in selling prices for specialty products typically lag the rising cost of crude oil and may be difficult to implement when crude oil costs increase dramatically over a short period of time.

The sale of refined products to the wholesale market is an important part of our business going forward, and if we fail to grow and maintain our market share or gain market acceptance of our refined products, our operating results could suffer.

Selling refined products to the wholesale market is an important part of our business, and as our refined products revenue increases as a portion of our overall revenue, our success in the wholesale market becomes increasingly important to our operating results. Our success in the wholesale market depends in large part on our ability to grow and maintain our image and reputation as an independent operator and to expand into and gain market acceptance of our refined products. Adverse perceptions of product quality, whether or not justified, or allegations of product quality issues, even if false or unfounded, could tarnish our reputation and cause our wholesale customers to choose refined products offered by our competitors.

We are dependent on third-party operators for the transportation of crude oil into and refined products out of our Nixon Facility, and if these third-party operators become unavailable to us, our ability to process crude oil and sell refined products to wholesale markets could be materially and adversely affected.

Table of Contents

Index to Financial Statements

We rely on trucks for the receipt of crude oil into and the sale of refined products out of our Nixon Facility. Since we do not own or operate any of these trucks, their continuing operation is not within our control. If any of the third-party trucking companies that we use, or the trucking industry in general, become unavailable to transport crude oil or our refined products because of acts of God, accidents, government regulation, terrorism or other events, our revenue and net income would be materially and adversely affected.

Potential downtime for maintenance at the Nixon Facility could reduce our revenue and cash available for payments of our obligations.

Although currently operating at anticipated levels, the Nixon Facility is still in a recommissioning phase and may require additional unscheduled downtime for unanticipated maintenance or repairs. Any scheduled or unscheduled maintenance reduces our revenues and increases our operating expenses during the period of time that our processing unit is not operating and could reduce our ability to meet our payment obligations.

Our operations, including our operation of the Nixon Facility, subject us to the inherent risk of incurring significant environmental costs and liabilities.

There is inherent risk of incurring significant environmental costs and liabilities in the operation of the Nixon Facility due to our handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to our operations, and as a result of historical operations and waste disposal practices of prior owners of our facilities. We currently own or operate properties that for many years have been used for industrial activities, including refining or terminal storage operation. Private parties, including the owners of properties adjacent to our operations and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may not be able to recover some or any of these costs from insurance or other sources of indemnity. To the extent that the costs associated with meeting any or all of these requirements are substantial and not adequately provided for, there could be a material adverse effect on our business, financial condition, and results of operations.

Our relationship with LEH and our related party transactions with LEH and its affiliates may cause conflicts of interest that may adversely affect us.

LEH owns approximately eighty percent (80%) of our issued and outstanding Common Stock. Jonathan P. Carroll, our Chief Executive Officer, President, Assistant Treasurer and Secretary, and Tommy L. Byrd, our interim Chief Financial Officer, Treasurer and Assistant Secretary, are also a member and Chief Financial Officer, respectively, of LEH and as a result may, under certain circumstances, have interests that differ from or conflict with our interests. Further, pursuant to the Management Agreement, LEH manages and operates the Nixon Facility and Blue Dolphin s other operations. As a result of their relationship with LEH, Messrs. Carroll and Byrd may experience conflicts of interest in the execution of their duties on behalf of Blue Dolphin including with respect to the Management Agreement.

LEH has no fiduciary duty to make decisions in our best interest. LEH is entitled to vote the Common Stock it owns in accordance with its interests, which may be contrary to our interests and those of other stockholders. LEH has interests that differ from the interests of our stockholders and, as a result, there is a risk that important business decisions will not be made in the best interest of our stockholders. LEH and its other affiliates are not limited in their ability to compete with us and are not obligated to offer us business opportunities. We believe that the transactions and agreements that we have entered into with LEH and its affiliates are on terms that are at least as favorable as could reasonably have been obtained at such time from third parties. However, these relationships could create, or appear to create, potential conflicts of interest when our Board is faced with decisions that could have different implications for us and LEH or its affiliates. The appearance of conflicts, even if such conflicts do not materialize, might

Table of Contents

Index to Financial Statements

adversely affect the public s perception of us, as well as our relationship with other companies and our ability to enter into new relationships in the future, which may have a material adverse effect on our ability to do business.

LEH holds a significant interest in us.

LEH owns approximately eighty percent (80%) of our issued and outstanding Common Stock. Through its ownership of such a large amount of Common Stock, LEH has significant influence over matters such as the election of our Board, control over our business, policies and affairs and other matters submitted to our stockholders.

Declines in throughput volumes and production rates from our leasehold properties in the U.S. Gulf of Mexico are expected to continue.

In recent years, throughput volumes on our pipelines and production rates from our leasehold properties in the U.S. Gulf of Mexico have continued to decline as a result of decreased activity in the U.S. Gulf of Mexico and depleting reserves. Following the April 2010 Deepwater Horizon explosion and oil spill, regulators have continued to move slowly in issuing new drilling permits in the U.S. Gulf of Mexico. This has negatively impacted our ability to attract new producers/shippers to our pipelines and make additional investments in new oil and gas properties. Although our U.S. Gulf of Mexico oil and gas properties may continue to operate over the next twelve to eighteen months, we expect the operating costs to exceed gross revenues based on current reserves and net cash flow estimates making these properties uneconomic.

During the past year, we have been primarily dependent on revenue from one key customer.

As a result of decreased revenue from pipeline operations and oil and gas sales related to our U.S. Gulf of Mexico leasehold interests, revenue from the North Sumatra Basin-Langsa Field accounted for approximately 54% of our total revenue in 2011 compared to approximately 26% in 2010. Unless we are able to offset this revenue with revenue from the sale of refined products, transportation throughput, interests in other oil and gas properties or other revenue generating assets at an acceptable cost, our financial condition could be materially adversely affected if production from the North Sumatra Basin-Langsa Field declines sharply or ceases.

If we are not able to generate sufficient funds from operations or obtain financing from other sources, we may not be able to continue our operations.

In recent years we have used a portion of our cash reserves to fund working capital requirements that were not funded from our operations. Continued pipeline underutilization, low commodity prices, production problems, reserve declines, unfavorable drilling results and other factors beyond our control could further reduce funds from our operations. Currently, we project that our current cash reserves will be sufficient to meet our obligations. If we are unable to realize the benefits of our acquisition of LE or obtain additional funds, we may have to seek debt and/or equity financing to meet our working capital requirements. Our history of losses may affect our ability to raise additional capital and increase the cost and terms of obtaining such financing. In the event we are not able to raise additional capital, we may be forced to sell our assets or discontinue our operations.

A substantial and extended decline in the prices of oil or gas would have a material adverse effect on our operations.

Our revenue, profitability, operating cash flow and potential for growth are largely dependent on prevailing oil and natural gas prices. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include:

- weather conditions;
- the domestic and international economy;
- Organization of Petroleum Exporting Countries actions;
- governmental regulation;
- political stability in the Middle East, South America and elsewhere;
- foreign supply of oil and natural gas;
- price of foreign imports;
- availability of alternate fuel sources; and
- the value of the U.S. dollar in relation to other currencies.

In addition, low or declining oil and natural gas prices could have collateral effects that could adversely affect us, including the following:

- reducing the exploration for and development of oil and gas by third-party companies operating in the vicinity of our pipeline systems;
- increasing our dependence on external sources of capital to meet our cash needs; and
- impairing our ability to obtain needed capital.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Estimating reserves of oil and gas is complex. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, including oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;

- the accuracy of various mandated economic assumptions; and

- the judgment of the persons preparing the estimate.

The proved reserve information set forth in this report is based on estimates prepared by third-party petroleum engineering consulting firms based on information that we provided. Although our U.S. Gulf of Mexico oil and gas properties may continue to operate over the next twelve to eighteen months, we expect the operating costs to exceed gross revenues based on current reserves and net cash flow estimates making these properties uneconomic. Actual quantities of recoverable oil and gas reserves, future production, oil and gas prices, taxes, development expenditures, abandonment costs and operating expenses prepared by others will likely vary from these estimates. Any significant variance could materially affect the quantities and net present value of our reserves. Furthermore, the present value of future net cash flows will most likely not equate to the current market value of their estimated proved oil and gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves were based on the historical 12-month average price (based on the first of the month pricing for the most recently ended fiscal year) and costs in effect at December 31, 2011. Actual future prices and costs may be materially different from the prices and costs they used.

We cannot control the activities on properties we do not operate.

Currently, third parties operate or control the development and operation of the oil and gas properties in which we have an interest. As a result, we depend on these third-parties to properly conduct lease acquisition, drilling, completion and production operations. The failure of any such third party operator or drilling contractors, as well as other service providers working on their behalf, to properly perform services or to act in ways that are in our best interest, could adversely affect our interests.

Table of Contents

Index to Financial Statements

We own and generally anticipate that we will continue to own substantially less than a 50% working interest in our oil and gas prospects and properties and will therefore engage in joint operations with other working interest owners. Since we own or control less than a majority of the working interest, decisions affecting our interest could be made by the owners of a majority of the working interest. For instance, if we are unwilling or unable to participate in the costs of operations approved by owners of a majority of the working interests in a well, our working interest in the well (and possibly other wells on the property) will likely be subject to contractual non-consent penalties. These penalties may include, full or partial forfeiture of our interest in the well or a relinquishment of our interest in production from the well in favor of the participating working interest owners until the participating working interest owners have recovered a multiple of the costs which would have been borne by us if we had elected to participate, which often ranges from 400% to 600% of such costs.

The geographic concentration of our assets may have a greater effect on us compared to other companies.

The majority of our onshore assets are located in the eagle Ford Shale and Gulf Coast areas of Texas, while the majority of our offshore assets are located in the U.S. Gulf of Mexico. As a result, we are at a greater risk of being impacted by local and regional conditions compared to oil and gas companies that have their assets more geographically diversified. Any negative regional event, including commodity price fluctuations, natural disasters and restrictive governmental regulations could adversely impact our business.

Strong competition from larger companies may negatively impact our ability to continue our operations.

The oil and gas industry is highly competitive. Our competitors include major integrated oil and gas companies, large independent energy companies, affiliates of major interstate and intrastate pipelines and national and local refinery operators and gatherers, many of which possess greater financial and other resources than we do. Our ability to successfully compete in the marketplace is affected by many factors, including our ability to access capital and absorb risks. We believe these factors largely put us at a competitive disadvantage in consummating transactions and acquiring new assets.

We intend to continue pursuing acquisitions. Our business may be adversely affected if we cannot effectively integrate acquired operations.

One of our business strategies is to acquire operations that are complementary to our existing business operations. The evaluation of opportunities involves time and expense, and acquiring operations and assets involves financial, operational and legal risks, including, but not limited to:

- inadvertently becoming subject to liabilities of the acquired company that were unknown to us at the time of the acquisition, such as later asserted litigation matters or tax liabilities;
- the difficulty of assimilating operations, systems and personnel of the acquired businesses; and
- maintaining uniform standards, controls, procedures and policies.

Competition from other potential buyers could cause us to pay a higher price than we otherwise might have paid and reduce our acquisition opportunities. We are often out-bid by larger, better capitalized companies for the acquisition opportunities that we pursue.

Operating hazards may adversely affect our ability to conduct business.

Our operations are subject to inherent risks normally associated with oil and gas operations, including, but not limited to:

- fires and explosions;

Table of Contents

Index to Financial Statements

- pollution;
- pipeline ruptures;
- sudden violent expulsions of oil, gas and mud while drilling a well, commonly referred to as a blowout;
- a cave in and collapse of the earth s structure surrounding a well, commonly referred to as cratering; and
- other environmental risks.

If any of these events were to occur, we could suffer substantial losses from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are also subject to a variety of operating risks exclusive to the marine environment, such as hurricanes or other adverse weather conditions and restrictive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

Our pipelines and other assets face operating hazards, and the potential limits on insurance coverage could expose us to potentially significant liability costs.

Our pipelines, exploration and production and other assets are subject to certain operating hazards, and our cash flow from those operations, if any, could decline as a result of a major accident, explosion or fire, severe weather or other natural disaster, or otherwise is forced to curtail its operations or shut down. These operating hazards could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in significant curtailment or suspension of our related operations.

Although we maintain insurance policies, including personal and property damage and business interruption insurance for each of our facilities with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent, we cannot ensure that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or significant interruption of operations. Furthermore, we may be unable to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. In addition, we are not fully insured against all risks incident to our business because certain risks are not fully insurable, coverage is unavailable or premium costs, in our judgment, do not justify such expenditures. For example, we are not insured for environmental accidents at all of our facilities.

Our business requires the retention and recruitment of a skilled workforce and the loss of key employees could result in the failure to implement our business plan.

The success of our business operations depends largely upon the efforts of key executive officers and technical personnel. Given our small size, we may not be able to retain required personnel on acceptable terms due to the competition for experienced personnel from other companies in the industry.

Compliance with environmental and other government regulations could be costly and could negatively impact our operations.

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

require the acquisition of a permit before operations can be commenced;

Table of Contents

Index to Financial Statements

- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling and pipeline activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and abandoning pipelines; and
- impose substantial liabilities for pollution resulting from our operations.

The recent trend toward stricter standards in environmental legislation and regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages. However, we do not believe that insurance coverage for all environmental damages that occur over time or complete coverage for sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or may lose the privilege to continue to operate our properties if certain environmental damages occur.

The EPA imposes a variety of regulations on responsible parties related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the EPA, could have a material adverse impact on us.

Regulation of greenhouse gas emissions could increase our operational costs and reduce demand for our products.

Continued political attention to issues concerning climate change, the role of human activity in it, and potential mitigation through regulation could have a material impact on our operations and financial results.

International agreements and national or regional legislation and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. These and other greenhouse gas emissions-related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted in each jurisdiction, our activities in the particular jurisdiction and market conditions. Greenhouse gas emissions that could be regulated include those arising from the conversion of crude oil into refined products, the transportation of crude oil and natural gas, and the exploration and production of crude oil and natural gas. Some matters related to these activities, such as actions taken by our competitors in response to such laws and regulations, are beyond our control.

The effect of regulation on our financial performance will depend on a number of factors including, among others, the sectors covered, the greenhouse gas emissions reductions required by law, the extent to which we would be entitled to receive emission allowance allocations or would need to purchase compliance instruments on the open market or through auctions, the price and availability of emission allowances and credits and the impact of legislation or other regulation on our ability to recover the costs incurred through the pricing of our products. Material price increases or incentives to conserve or use alternative energy sources could also reduce demand for products we currently sell and adversely affect our sales volumes, revenues and margins.

Table of Contents

Index to Financial Statements

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information appearing in Item 1. Business describing our business activities is incorporated herein by reference.

Our principal executive office, which is leased, is located at 801 Travis Street, Suite 2100, Houston, Texas 77002.

ITEM 3. LEGAL PROCEEDINGS

Pursuant to a Settlement Agreement and Mutual Release by and among Blue Dolphin, LEH and Lazarus Louisiana Refinery II, LLC (LLRII) effective February 15, 2012, the parties agreed to settle and compromise all disputes between them in connection with closing of the Acquisition. LEH has agreed to file a non-suit with prejudice of all pending claims against Blue Dolphin under Cause No. 210-32561, styled *Blue Dolphin Energy Company v. Lazarus Energy Holdings, L.L.C. and Lazarus Louisiana Refinery II, L.L.C.,* in the 129th District Court of Harris County, Texas (the Lawsuit). Blue Dolphin has agreed that it will not execute or attempt to execute on an order that was signed on May 16, 2011 in the Lawsuit severing LEH s counterclaims into Cause No. 2010-32561-A, which resulted in a Partial Summary Judgment becoming a final judgment in Blue Dolphin s favor.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Price for Common Stock

Our Common Stock is quoted on the OTCQX U.S. Premier tier under the ticker symbol BDCO. As of March 30, 2012, we had 292 record holders of our Common Stock. Based on the record date for our 2011 annual meeting of stockholders, which was held on January 27, 2012, we had approximately 3,000 beneficial holders of our Common Stock.

The following table sets forth, for the periods indicated, the high and low prices for our Common Stock as reported by the Nasdaq and the OTC Markets. The quotations reflect inter-dealer prices, without adjustment for retail mark-ups, markdowns or commissions and may not represent actual transactions.

Quarter Ended	High	Low
2011		
December 31	$ 4.47	$ 2.00
September 30	$ 3.50	$ 2.19
June 30	$ 8.91	$ 1.30
March 31	$ 9.09	$ 2.21
2010(1)		
December 31	$ 2.88	$ 1.70
September 30	$ 3.64	$ 0.99
June 30	$ 4.90	$ 1.33
March 31	$ 3.71	$ 2.24

(1) Prices for September 30, June 30 and March 31, 2010 have been adjusted to reflect our 1-for-7 reverse stock split, which occurred in the quarter ended September 30, 2010.

(2) Between June 13, 2011 and September 1, 2011, our Common Stock traded on the OTCQB.

Simultaneous with the delisting of our Common Stock from the Nasdaq Capital Market on February 28, 2012, our Common Stock began trading on the OTCQX U.S. Premier tier of the OTC Markets under the ticker symbol BDCO See Recent Developments in Part I, Item 1. Business of this report for additional information related to Nasdaq s decision to delist our Common Stock.

Dividend Policy

We have not declared or paid any dividends on our Common Stock since our incorporation. We currently intend to retain earnings for our capital needs and expansion of our business and do not anticipate paying cash dividends on the Common Stock in the foreseeable future. We expect that any loan agreements we enter into in the future will likely contain restrictions on the payment of dividends on our Common Stock. Future policy with respect to dividends will be determined by the Board based upon our earnings and financial condition, capital requirements and other considerations. We are a holding company that conducts substantially all of our operations through our subsidiaries. As a result, our ability to pay dividends on the Common Stock will also be dependent upon the cash flow of our subsidiaries.

Table of Contents

Index to Financial Statements

Equity Compensation Plan Information

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2011, under which our equity securities were authorized for issuance:

Securities Authorized for Issuance under Equity Compensation Plans

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders	28,887	$ 13.29	80,495
Equity compensation plans not approved by security holders			
Total	28,887	$ 13.29	80,495

Remainder of Page Intentionally Left Blank

30

Table of Contents

Index to Financial Statements

ITEM 6. SELECTED FINANCIAL DATA

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
2011					
Revenue from operations:					
Pipeline operations	$ 342,630	$ 267,375	$ 219,006	$ 102,489	$ 931,500
Oil and gas sales	349,704	353,027	301,417	338,570	1,342,718
Total revenue from operations	692,334	620,402	520,423	441,059	2,274,218
Cost of operations:					
Pipeline operating expenses	221,334	245,032	532,931	9,562	1,008,859
Lease operating expenses	258,443	271,836	286,439	357,534	1,174,252
Depletion, depreciation and amortization	146,708	136,828	123,355	185,036	591,927
Impairment of oil and gas properties				252,706	252,706
General and administrative expenses	473,391	349,245	293,567	458,161	1,574,364
Accretion expense	33,086	32,993	32,805	32,806	131,690
Loss (gain) on sale of property and equipment			(3,267,070)	186,017	(3,081,053)
Total cost of operations	1,132,962	1,035,934	(1,997,973)	1,481,822	1,652,745
Income (loss) from operations	(440,628)	(415,532)	2,518,396	(1,040,763)	621,473
Other income (expense), including income tax expense	8,540	1,598	5,138	(18,814)	(3,538)
Net income (loss)	$ (432,088)	$ (413,934)	$ 2,523,534	$ (1,059,577)	$ 617,935
Income (Loss) per share:					
Basic	$ (0.21)	$ (0.20)	$ 1.20	$ (0.50)	$ 0.30
Diluted	$ (0.21)	$ (0.20)	$ 1.20	$ (0.50)	$ 0.29
2010					
Revenue from operations:					
Pipeline operations	$ 429,087	$ 462,392	$ 502,369	$ 485,038	$ 1,878,886
Oil and gas sales	19,022	21,199	237,940	584,524	862,685
Total revenue from operations	448,109	483,591	740,309	1,069,562	2,741,571
Cost of operations:					
Pipeline operating expenses	286,988	325,323	243,531	242,755	1,098,597
Lease operating expenses	21,188	7,824	221,019	423,737	673,768
Depletion, depreciation and amortization	117,846	128,855	217,105	155,523	619,329
Recovery of allowance for doubtful loanreceivable			(201,000)		(201,000)
General and administrative expenses	479,222	359,027	306,288	283,266	1,427,803
Stock based compensation	40,320	13,440			53,760
Accretion expense	29,058	29,057	30,563	31,316	119,994
Total cost of operations	974,622	863,526	817,506	1,136,597	3,792,251
Other income (expense), including income tax expense	759	9,998	8,115	8,913	27,785
Net loss	$ (525,754)	$ (369,937)	$ (69,082)	$ (58,122)	$ (1,022,895)
Loss per share:					

Basic and diluted	$	(0.26)	$	(0.22)	$	(0.04)	$	(0.03)	$	(0.55)

Table of Contents

Index to Financial Statements

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

The following is a review of certain aspects of our financial condition and results of operations and should be read in conjunction with Item 1, Business and Item 8, Financial Statements and Supplementary Data, as well as the Notes to Consolidated Financial Statements.

Executive Summary

As of December 31, 2011, we operated two lines of business through our subsidiaries: (i) pipeline transportation services to producers/shippers, and (ii) oil and gas exploration and production. Our pipeline assets are located primarily offshore in the Texas Gulf Coast area and our leasehold interests in properties are located in the U.S. Gulf of Mexico and the North Sumatra Basin offshore Indonesia.

Pipeline Operations.

- *BDPS* The BDPS is currently transporting an aggregate of approximately 3 MMcf of gas per day, which represents 1% of throughput capacity.

- *GA 350* The GA 350 is currently transporting an aggregate of approximately 9 MMcf of gas per day, which represents 14% of throughput capacity.

Exploration and Production.

- *North Sumatra Basin-Langsa Field* The H-4 Well is currently producing approximately 370 barrels of oil per day.

- *High Island Block 115* The B-1 ST2 Well is currently producing approximately 2 MMcf of gas per day.

- *Galveston Area Block 321* The A-4 Well is currently producing approximately 2 MMcf of gas per day.

- *High Island Block 37* The block contains no active wells.

In recent years, throughput volumes on our pipelines and production rates from our leasehold properties in the U.S. Gulf of Mexico have continued to decline as a result of decreased activity in the Gulf of Mexico and depleting reserves. Following the April 2010 Deepwater Horizon explosion and oil spill, regulators have moved slowly to issue new drilling permits in the Gulf of Mexico. This has negatively impacted our ability to attract new producers/shippers to our pipelines and to acquire additional leasehold interests. Although our U.S. Gulf of Mexico oil and gas properties may continue to operate over the next twelve to eighteen months, we expect the operating costs to exceed gross revenues based on current reserves and net cash flow estimates making these properties uneconomic. As a result of the Acquisition, we anticipate that our core focus going forward will be crude oil and condensate processing.

[Table of Contents](#)

[Index to Financial Statements](#)

Results of Operations

For the year ended December 31, 2011 (the current period), we reported net income of $617,935 compared to a net loss of $1,022,895 for the year ended December 31, 2010 (the previous period). For the three months ended December 31, 2011 (the current quarter), we reported a net loss of $1,059,577 compared to a net loss of $58,122 for the three months ended December 31, 2010 (the previous quarter).

2011 Compared to 2010

Revenue from Pipeline Operations. Revenue from pipeline operations decreased by $947,386, or 50%, in the current period to $931,500. Revenue in the current period from the BDPS totaled approximately $659,500 compared to approximately $1,538,000 in the previous period primarily due to lower volumes of transported gas. Daily gas volumes transported through the BDPS averaged approximately 5 MMcf of gas per day in the current period compared to approximately 14 MMcf of gas per day in the previous period. Revenue on the GA 350 decreased by approximately $69,000 to approximately $272,000 in the current period primarily due to natural production declines. Daily gas volumes transported through the GA 350 decreased to approximately 14 MMcf of gas per day in the current period from approximately 17 MMcf of gas per day in the previous period.

Revenue from Oil and Gas Sales. Revenue from oil and gas sales increased by $480,033, or 56%, to $1,342,718 in the current period primarily due to production from the North Sumatra Basin-Langsa Field.

Our average realized gas price per Mcf in the current period was $3.71 compared to $3.85 in the previous period. The sales mix by product was 93% oil and 7% gas. Our average realized price per barrel of oil was $118.59 in the current period compared to $88.14 in the previous period.

Revenue breakdown for the current period by field was approximately $1,222,400 for the North Sumatra Basin-Langsa Field, $84,200 for High Island Block 115, $26,900 for Galveston Area Block 321 and $9,200 for High Island Block 37. Revenue breakdown for the previous period by field was approximately $720,300 for the North Sumatra Basin-Langsa Field, $48,900 for High Island Block 115, $48,200 for Galveston Area Block 321 and $45,300 for High Island Block 37.

Pipeline Operating Expenses. Pipeline operating expenses decreased by $89,738, or 8%, to $1,008,859 in the current period. The decrease was primarily due to decreases in insurance expense, chemicals, saltwater disposal transportation costs, property taxes and other operating expenses. The decreases were partially offset by an increase in legal expenses, related to the sale of the Buccaneer Pipeline.

Lease Operating Expenses. Lease operating expenses increased $500,484, or 74%, in the current period to $1,174,252 primarily due to expenses from the North Sumatra Basin-Langsa Field. Lease operating costs associated with North Sumatra Basin-Langsa Field totaled approximately $1,098,500 for the current period.

Depletion, Depreciation and Amortization. Depletion, depreciation and amortization decreased by $27,402, or 4%, in the current period to $591,927 primarily due to lower depletion of the North Sumatra Basin-Langsa Field.

Impairment of Oil and Gas Properties. We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the ceiling, based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves, calculated using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. Our ceiling for the current period was

Table of Contents

Index to Financial Statements

calculated using domestic prices of $96.04 per barrel of oil and $4.18 per Mcf of gas and an international price of $114.95 per barrel of oil. At December 31, 2011, our costs exceeded our ceiling limitation, resulting in a write-down of our U.S. Gulf of Mexico oil and gas properties of $252,706. Our ceiling for the previous period was calculated using prices of $79.61 per barrel of oil and $4.33 per Mcf of gas.

General and Administrative Expenses and Stock Based Compensation. General and administrative expenses and stock based compensation expenses increased by $146,561, or 10%, in the current period to $1,574,364 primarily due to increases in franchise tax, employee bonuses, employee insurance, shareholder reporting expenses and software maintenance fees. The increases were partially offset by decreases in officer salaries, consulting and audit expense.

Gain on Sale of Property and Equipment. During the current period, BDPL sold its eighty-three and one-third percent (83 $^{1}/3$%) undivided interest in the Buccaneer Pipeline to Sunoco for proceeds of approximately $3.6 million in cash. The gain on the sale was approximately $3.1 million

Recovery of Allowance for Doubtful Loan Receivable. Recovery for allowance for doubtful loan receivable reduced by $201,000 in the current period primarily due to the addition of a disposal well, with a fair market value of $201,000, which was recorded as a recovery of a bad debt expense on an outstanding loan receivable, net of credited and recovered amounts in the previous period.

Three Months Ended December 31, 2011 Compared to Three Months Ended December 31, 2010

Revenue from Pipeline Operations. Revenue from pipeline operations decreased by $382,549, or 79%, in the current quarter to $102,489 primarily due to the decrease in oil volumes transported. Revenue in the current quarter from the BDPS decreased to approximately $34,700 compared to approximately $397,500 in the previous quarter. Daily gas volumes transported on the BDPS averaged 1 MMcf of gas per day in the current quarter compared to 12 MMcf of gas per day in the previous quarter. Revenue on the GA 350 decreased to approximately $67,800 compared to approximately $87,500 in the previous quarter due to a decrease in average daily gas volumes transported of 13 MMcf of gas per day in the current quarter from 17 MMcf of gas per day in the previous quarter.

Revenue from Oil and Gas Sales. Revenue from oil and gas sales decreased by $245,945, or 42% to $338,570 in the current quarter primarily due to a reduction in production from the North Sumatra Basin-Langsa Field and High Island Block 115 in the same period.

Pipeline Operating Expenses. Pipeline operating expenses in the current quarter decreased by $233,193, or 96%, to $9,562 due to certain costs in the current quarter associated with the sale of the Buccaneer Pipeline and related assets to Sunoco that occurred in third quarter of 2011. Excluding this, pipeline operating expenses in the current quarter decreased $47,176, or 19%, due to decreases in pipeline repairs and maintenance costs, property taxes, saltwater disposal transportation costs and contract labor, which was offset by an increase in legal expenses.

Lease Operating Expenses. Lease operating expenses decreased in the current quarter by $66,203, or 15%, to $357,534 primarily as a result of decreased production from the North Sumatra Basin-Langsa Field.

Depletion, Depreciation and Amortization. Depletion, depreciation and amortization increased by $29,513, or 19%, in the current quarter to $185,036 primarily due to additional depletion on the domestic oil and gas properties.

General and Administrative Expenses and Stock Based Compensation. General and administrative expenses and stock based compensation expenses increased by $174,895, or 62%, to $458,161 in the current quarter primarily due to increases in shareholder reporting expenses, franchise tax, employee insurance, software maintenance fees and employee bonuses. The increases were partially offset by decreases in consulting expense.

Table of Contents

Index to Financial Statements

Impairment of Oil and Gas Properties. During the fourth quarter of the current period we recorded a full cost ceiling impairment of $252,706 on our U.S. Gulf of Mexico oil and gas properties.

Liquidity and Capital Resources

Sources and Uses of Cash. Our primary source of cash is cash flow from operations and cash on hand. During 2011, we had positive cash flow from operations of approximately $1,686,797 mainly due to the sale of the Buccaneer Pipeline and related assets to Sunoco for proceeds of approximately $3.6 million in cash.

The Nixon Facility will provide Blue Dolphin with positive cash flow. We expect to fund our operations, any additional capital expenditures related to the Nixon Facility and the potential acquisition of LED with the proceeds from the sale of refined products. Further, we expect our overall liquidity to increase in 2012 due to the revenue generated by the Nixon Facility.

We do not enter into any hedges or any type of derivatives to offset changes in commodity prices. We also do not have any outstanding debt or a credit facility with a bank or institution that may restrict us from issuing debt or Common Stock. At December 31, 2011, our current available cash was $1,941,221.

	For Year Ended December 31,	
	2011	2010
Cash flow from operations		
Loss from operations	$ (1,426,795)	$ (350,812)
Change in current assets and liabilities	(450,391)	226,219
Proceeds from sale of property and equipment	3,563,983	
Total cash flow from operations (including gain on disposal)	1,686,797	(124,593)
Cash outflows		
Capital expenditures and advance of loan receivable	(246,494)	(58,719)
Payments on financing activities	(124,936)	(207,317)
Total cash outflows	(371,430)	(266,036)
Total change in cash flows	$ 1,315,367	$ (390,629)

In recent years, we have used a portion of our cash reserves to fund our working capital requirements that were not funded from operations.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have changed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules at or before their adoption, and believe the proper implementation and consistent application of accounting rules is critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by comparatively analyzing similar situations and reviewing the accounting guidance governing them, and may consult with our independent registered independent accounting firm about the appropriate interpretation and application of these policies. Our most critical accounting policies currently relate to the accounting for the impairment of long-lived assets, which include primarily our oil and gas properties and our pipeline assets, as of December 31, 2011 and the accounting for future asset retirement costs.

Table of Contents

Index to Financial Statements

Accounting for the Impairment or Disposal of Long-Lived Assets. In accordance with the provisions of the Accounting Standards Codification (ASC) on accounting for the impairment or disposal of long-lived assets, we initiate a review for impairment of our long-lived assets whenever events or changes in circumstances indicate that the carrying amount of a long-lived asset may not be recoverable. Recoverability of an asset is measured by comparison of its carrying amount to the expected future undiscounted cash flows expected to result from the use and eventual disposition of that asset, excluding future interest costs that would be recognized as an expense when incurred. Any impairment to be recognized is measured by the amount by which the carrying amount of the asset exceeds its fair market value. Significant management judgment is required in the forecasting of future operating results which are used in the preparation of projected cash flows and, should different conditions prevail or judgments be made, material impairment charges could be necessary. Currently, our pipeline assets are significantly underutilized and such underutilization is an indicator of possible impairment at December 31, 2011. Accordingly, in reviewing our expected future cash flows as of December 31, 2011, we expect to be generated positive cash flow from our pipeline assets based on certain assumptions. The most significant assumption made in connection with the preparation of expected future cash flows is that pipeline throughput volumes will increase over the next few years due to increased leasing and drilling activities surrounding our pipelines from current and prospective oil and gas companies. Based on the results of the impairment test, which indicates expected future undiscounted cash flows are in excess of the pipeline assets net carrying value, no impairment was recorded at December 31, 2011.

Asset Retirement Obligations. The accounting for future abandonment costs changed in August 2001, with the adoption of guidance on accounting for asset retirement obligations. This guidance requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted towards its future value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Future asset retirement costs include costs to dismantle, relocate or dispose of our offshore platforms, pipeline systems and related onshore facilities, plugging and abandonment of wells and land and sea bed restoration costs. We develop these cost estimates for each of our assets based upon regulatory requirements, platform structure, water depth, reservoir characteristics, reservoir depth, equipment market demand, current procedures and construction and engineering consultations. Because these costs typically extend many years into the future, estimating these future costs are difficult and require management to make judgments that are subject to future revisions based upon numerous factors, including changing technology, political and regulatory environments. We review our assumptions and estimates of future abandonment costs on a quarterly basis.

Accounting for Uncertainty in Income Taxes. The current guidance clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements. It also prescribes 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. The standard also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

The evaluation of a tax position in accordance with the guidance is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The provisions of the guidance are to be applied to all tax positions. Only tax positions that meet the more-likely-than-not recognition threshold are recognized.

Table of Contents

Index to Financial Statements

The provisions of the guidance have been applied to all of our material tax positions taken through the fiscal year ended December 31, 2011. We have determined that all of our material tax positions taken in our income tax returns and the positions we expect to take in our future income tax filings meet the more likely-than-not recognition threshold prescribed by the guidance. In addition, we determined that, based on our judgment, none of these tax positions meet the definition of uncertain tax positions that are subject to the non-recognition criteria set forth in the pronouncement.

Fair Value Measurements. We follow guidance on fair value measurements, which clarifies the definition of fair value, establishes a framework for measuring fair value, and expands the disclosures on fair value measurements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not applicable.

Remainder of page intentionally left blank

Table of Contents

Index to Financial Statements

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
Index to Financial Statements:

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

Report of Independent Registered Public Accounting Firm

The Board of Directors and

Stockholders of Blue Dolphin Energy Company

Houston, Texas

We have audited the accompanying consolidated balance sheets of Blue Dolphin Energy Company and Subsidiaries (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders equity and cash flows for each of the years in the two-year period ended December 31, 2011. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas

March 30, 2012

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,941,221	$ 625,854
Accounts receivable, net of allowance for doubtful accounts	534,873	598,391
Loan receivable, net of allowance for loan receivable		
Prepaid expenses and other current assets	302,236	213,071
Total current assets	2,778,330	1,437,316
Property and equipment, at cost:		
Oil and gas properties (full-cost method)	2,321,913	2,222,535
Pipelines	4,373,262	4,659,686
Onshore separation and handling facilities	1,344,455	1,919,402
Land	473,225	860,275
Other property and equipment	557,374	503,813
	9,070,229	10,165,711
Less: Accumulated depletion, depreciation and amortization	5,449,061	5,630,730
Total property and equipment, net	3,621,168	4,534,981
Other assets	9,463	9,463
Total assets	$ 6,408,961	$ 5,981,760
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 441,699	$ 543,327
Note payable insurance		124,936
Asset retirement obligation current portion	203,448	192,470
Accrued expenses and other liabilities	18,679	2,142
Total current liabilities	663,826	862,875
Long-term liabilities:		
Asset retirement obligations, net of current portion	2,483,701	2,535,386
Total long-term liabilities	2,483,701	2,535,386
Total liabilities	3,147,527	3,398,261
Commitments and contingencies		
Stockholders equity:		
Common stock ($0.01 par value, 100,000,000 shares authorized, 2,098,390 and 2,078,514 shares issued and outstanding at December 31, 2011 and 2010, respectively)	20,984	20,785
Additional paid-in capital	33,753,061	33,693,260
Accumulated deficit	(30,512,611)	(31,130,546)
Total stockholder s equity	3,261,434	2,583,499

Total liabilities and stockholders equity	$ 6,408,961	$ 5,981,760

See accompanying notes to consolidated financial statements.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Operations

	Years Ended December 31, 2011	2010
Revenue from operations:		
Pipeline operations	$ 931,500	$ 1,878,886
Oil and gas sales	1,342,718	862,685
Total revenue from operations	2,274,218	2,741,571
Cost of operations:		
Pipeline operating expenses	1,008,859	1,098,597
Lease operating expenses	1,174,252	673,768
Depletion, depreciation and amortizaton	591,927	619,329
Impairment of oil and gas properties	252,706	
Recovery of allowance for doubtful loan receivable		(201,000)
General and administrative expenses	1,574,364	1,427,803
Stock-based compensation		53,760
Accretion expense	131,690	119,994
Gain on sale of property and equipment, less disposal costs	(3,081,053)	
Total cost of operations	1,652,745	3,792,251
Income (loss) from operations	621,473	(1,050,680)
Other income (expense):		
Interest and other income	17,383	32,370
Total other income (expense)	17,383	32,370
Income (loss) before income taxes	638,856	(1,018,310)
Income tax expense	(20,921)	(4,585)
Net income (loss)	$ 617,935	$ (1,022,895)
Income (loss) per common share:		
Basic	$ 0.30	$ (0.55)
Diluted	$ 0.29	$ (0.55)
Weighted average number of common shares outstanding:		
Basic	2,093,840	1,864,354
Diluted	2,096,497	1,864,354

See accompanying notes to consolidated financial statements.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Stockholders Equity

	Common Stock Shares	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Total Stockholders Equity
Balance at December 31, 2009	1,696,710	$ 16,967	$ 32,880,208	$ (30,107,651)	$ 2,789,524
Common stock issued for acquisition	342,857	3,429	682,285		685,714
Common stock issued for services	39,987	400	79,600		80,000
Stock-based compensation			53,760		53,760
Retirement of fractional shares	(1,040)	(11)	(2,593)		(2,604)
Net loss				(1,022,895)	(1,022,895)
Balance at December 31, 2010	2,078,514	20,785	33,693,260	(31,130,546)	2,583,499
Common stock issued for services	19,876	199	59,801		60,000
Net income				617,935	617,935
Balance at December 31, 2011	2,098,390	$ 20,984	$ 33,753,061	$ (30,512,611)	$ 3,261,434

See accompanying notes to consolidated financial statements.

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Cash Flows

	Years Ended December 31, 2011	2010
OPERATING ACTIVITIES		
Net income (loss)	$ 617,935	$ (1,022,895)
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Depletion, depreciation and amortization	591,927	619,329
Gain on sale of property and equipment	(3,081,053)	
Recovery of previous allowance for doubtful loan receivable		(201,000)
Impairment of oil and gas properties	252,706	
Accretion expense	131,690	119,994
Stock-based compensation		53,760
Common stock issued for services	60,000	80,000
Changes in operating assets and liabilities:		
Accounts receivable	63,518	(170,267)
Prepaid expenses and other current assets	(89,165)	302,949
Settlement of asset retirement obligations	(339,653)	(45,525)
Accounts payable, accrued expenses and other liabilities	(85,091)	139,062
Net cash used in operating activities	(1,877,186)	(124,593)
INVESTING ACTIVITIES		
Purchases of property and equipment	(246,494)	(58,719)
Proceeds from sale of property and equipment	3,563,983	
Net cash provided by (used in) investing activities	3,317,489	(58,719)
FINANCING ACTIVITIES		
Payments on notes payable	(124,936)	(204,713)
Retirement of fractional shares		(2,604)
Net cash used in financing activities	(124,936)	(207,317)
Increase (decrease) in cash and cash equivalents	1,315,367	(390,629)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	625,854	1,016,483
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 1,941,221	$ 625,854
Non-cash investing and financing activities:		
Financing of insurance premiums	$	$ 156,170
Purchase of property and equipment with company stock	$	$ 685,714
Property and equipment acquired as partial settlement of loan receivable	$	$ 201,000
Increase in asset retirement obligation and property and equipment	$ 167,256	$ 391,369

See accompanying notes to consolidated financial statements.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements

NOTES TO CONDOLIDATED FINANCIALSTATEMENTS

(1) Organization and Significant Accounting Policies
Organization

Blue Dolphin Energy Company (Blue Dolphin, we and our) was incorporated in Delaware in January 1986 to engage in oil and gas exploration, production and acquisition activities and oil and gas transportation and marketing services. We were formed pursuant to a reorganization effective June 9, 1986.

Principles of Consolidation

Our consolidated financial statements include the accounts of our wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Reverse Stock Split

On June 9, 2010 our stockholders approved a reverse stock split of our common stock, par value $0.01 per share (the Common Stock) at a ratio within a range from 1 for 5 (1:5) to 1 for 10 (1:10), at the discretion of the Board, at any time prior to September 1, 2010. The Board set the reverse stock split ratio at 1 for 7 (1:7) on June 30, 2010. The effective date for the reverse stock split was July 16, 2010. No fractional shares were issued in connection with the reverse stock split. Each holder of Common Stock who would otherwise be entitled to receive a fractional share of Common Stock was, in lieu of such fractional share, paid in cash at fair market value. We paid approximately $2,604 for the repurchase of fractional shares.

In addition, the Board elected not to alter the number of authorized shares or change the par value of the Common Stock, such number of authorized shares remaining at 100,000,000 shares and such par value remaining a $0.01 per share. Earnings per share, common stock outstanding and weighted average common stock outstanding as referred to in these consolidated financial statements have been restated, where applicable, to give retroactive effect of the reverse stock split.

Accounting Estimates

We have made a number of estimates and assumptions relating to the reporting of consolidated assets and liabilities and to the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) as codified by the Financial Accounting Standards Board (FASB) in its Accounting Standards Codification (ASC), pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC). This includes assessing the realization of the note receivable, the estimated useful life of pipeline assets, valuation of stock-based payments and reserve information, which affects the depletion calculation as well as the full cost ceiling limitation. While we believe current estimates are reasonable and appropriate, actual results could differ from those estimated.

Cash and Cash Equivalents

Cash equivalents include liquid investments with an original maturity of three months or less. We maintain cash and cash equivalent balances at one financial institution that is insured by the Federal Deposit Insurance Corporation (the FDIC). Cash balances are maintained in depository and overnight investment accounts with financial institutions which at times, exceed insured limits. We monitor the financial condition of the financial institutions and have experienced no losses associated with these accounts.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

In October 2008, the FDIC amended its deposit insurance provisions to increase the basic limit amount from $100,000 to $250,000 per depositor. The coverage increase, which was intended to be temporary, was to revert back to $100,000 per depositor limit on December 31, 2009. However, in May 2009, the FDIC extended the coverage date through December 31, 2013. The temporary increase was made permanent in 2010 by the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Oil and Gas Properties

Oil and gas properties are accounted for using the full-cost method of accounting, whereby all costs associated with acquisition, exploration, and development of oil and gas properties, including directly related internal costs, are capitalized on a cost center basis. We use one cost center for our U.S. Gulf of Mexico properties and one cost center for our Indonesian properties. Amortization of such costs and estimated future development costs are determined using the unit-of-production method. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties or impairment has occurred.

Estimated proved oil and gas reserves are based upon reports prepared by third-party petroleum engineering consulting firms. The net carrying value of oil and gas properties, less related deferred income taxes, is limited to the lower of unamortized cost or the cost center ceiling, defined as the sum of the present value (10% discount rate applied) of estimated future net revenue from proved reserves, after giving effect to income taxes, and the lower of cost or estimated fair value of unproved properties. Since our unamortized cost exceeded the present value of estimated future net revenue from domestic operations, we recorded an impairment to our U.S. Gulf of Mexico oil and gas properties of $252,706 in 2011. We recorded no such impairment in 2010. Disposition of oil and gas properties is recorded as adjustments to capitalized costs, with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves.

We capitalize interest on expenditures made in connection with significant exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. No interest has been capitalized for the years reflected herein.

Pipelines and Facilities

Pipelines and facilities are recorded at cost. Depreciation is computed using the straight-line method over estimated useful lives ranging from 10 to 22 years.

In accordance with the ASC on accounting for the impairment or disposal of long-lived assets, assets are grouped and evaluated for impairment based on the ability to identify separate cash flows generated therefrom. We did not have any impairment of our pipelines and facilities for the years ended December 31, 2011 and 2010. During the year, BDPL sold its eighty-three and one-third percent (83 1/3%) undivided interest in the Buccaneer Pipeline to Sunoco Partners Marketing and Terminals L.P. (Sunoco). BDPL still maintains its 83 1/3% undivided interest in the Galveston Area Block 350 Pipeline, as well as an 83 1/3% undivided interest in the Omega Pipeline.

Other Property and Equipment

Depreciation of furniture, fixtures and other equipment is computed using the straight-line method over estimated useful lives ranging from 3 to 10 years.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Asset Retirement Obligations

We follow the guidance on accounting for asset retirement obligations, which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset.

The guidance requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. If the obligation is settled for other than the carrying amount of the liability, a gain or loss on settlement is recognized.

We have asset retirement obligations associated with the future abandonment of our pipelines and related facilities and our offshore oil and gas properties. The following table summarizes our asset retirement obligation transactions during the years ended December 31, 2011 and 2010.

	Years Ended December 31,	
	2011	2010
Beginning asset retirement obligations	$ 2,727,856	$ 2,262,018
Liabilities incurred	167,256	391,877
Liabilities settled	(339,653)	(46,033)
Accretion expense	131,690	119,994
Ending asset retirement obligations	$ 2,687,149	$ 2,727,856

Stock-Based Compensation

Stock-based compensation is recognized in our consolidated financial statements based on the fair value, on the date of grant or modification, of the equity instrument awarded. Stock-based compensation expense is recognized in the consolidated financial statements on a straight-line basis over the requisite service period for the entire award.

Recognition of Oil and Gas Revenue

Sales from producing wells are recognized on the entitlement method of accounting, which defers recognition of sales when, and to the extent that, deliveries to customers exceed our net revenue interest in production. Similarly, when deliveries are below our net revenue interest in production, sales are recorded to reflect the full net revenue interest. Our imbalance liability at December 31, 2011 was not material.

Recognition of Pipeline Transportation Revenue

Revenue from our pipelines is derived from fee-based contracts and is typically based on transportation fees per unit of volume transported multiplied by the volume delivered. Revenue is recognized when volumes have been physically delivered for the customer through the pipeline.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Allowance for Doubtful Accounts

Accounts receivable are customer obligations due under normal trade terms. The allowance for doubtful accounts represents our estimate of the amount of probable credit losses existing in our accounts receivable. We have a limited number of customers with individually large amounts due at any given date. Any unanticipated change in any one of these customers credit worthiness or other matters affecting the collectability of amounts due from such customers could have a material adverse effect on our results of operations in the period in which such changes or events occur. We regularly review all aged accounts receivables for collectability and establish an allowance as necessary for individual customer balances. As of December 31, 2011 and 2010, we did not record an allowance for doubtful accounts.

Income Taxes

We provide for income taxes using the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. 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. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

The evaluation of a tax position is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

Earnings Per Share

We apply the provisions of the ASC for computing earnings per share. The guidance requires the presentation of basic earnings per share (EPS) which excludes dilution and is computed by dividing net income (loss) available to common stockholders by the weighted-average number of shares of common stock outstanding for the period. The guidance requires dual presentation of basic EPS and diluted EPS on the face of the consolidated statement of operations and requires a reconciliation of the numerators and denominators of basic EPS and diluted EPS. Diluted EPS is computed by dividing net income (loss) available to common shareholders by the diluted weighted average number of common shares outstanding, which includes the potential dilution that could occur if securities or other contracts to issue common stock were converted to common stock that then shared in the earnings of the entity.

Employee stock options and stock warrants outstanding were not included in the computation of diluted earnings per share for the year ended December 31, 2010, because their assumed exercise and conversion would have an anti-dilutive effect on the computation of diluted income (loss) per share.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

The following table provides reconciliation between basic and diluted income (loss) per share:

	2011	2010
Basic and Diluted		
Net income (loss)	$ 617,935	$ (1,022,895)
Basic		
Weighted average number of shares of common stock outstanding	2,093,840	1,864,354
Per share amount	$ 0.30	$ (0.55)
Effect of dilutive stock options	2,657	
Diluted		
Weighted average number of shares of common stock outstanding and potential dilutive shares of common stock	2,096,497	1,864,354
Per share amount	$ 0.29	$ (0.55)
Employee stock options excluded from computation of diluted EPS because effect would be anti-dilutive	26,803	30,390

Environmental

We are subject to extensive domestic and foreign environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require us to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amounts and timing of payments is fixed or reliably determinable. As of December 31, 2011 and 2010, no environmental violation was recorded on our consolidated balance sheets.

(2) Fair Value of Financial Instruments

The carrying values of cash and cash equivalents, accounts receivable and accounts payable, accrued liabilities and other current liabilities approximate fair value due to the short-term maturities of these instruments.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(3) Loan Receivable

We recorded an allowance for doubtful loan receivable of $1.5 million at December 31, 2009. The loan receivable is associated with a $2.0 million loan, net of credited and recovered amounts (the Loan), made to Lazarus Louisiana Refinery II, LLC (LLRII) on July 31, 2009 and due on January 31, 2010. At December 31, 2011 and 2010, we maintained an allowance for the uncollected balance of the Loan.

Pursuant to a Settlement Agreement and Mutual Release dated February 15, 2012, by and among Blue Dolphin, Lazarus Energy Holdings, LLC (LEH) and LLRII, the parties agreed to settle and compromise all disputes between them in connection with closing of the Acquisition in the subsequent period. LEH has agreed to file a non-suit with prejudice of all pending claims against Blue Dolphin under Cause No. 210-32561, styled *Blue Dolphin Energy Company v. Lazarus Energy Holdings, L.L.C. and Lazarus Louisiana Refinery II, L.L.C.*, in the 129th District Court of Harris County, Texas (the Lawsuit). Blue Dolphin has agreed that it will not execute or attempt to execute on an order that was signed on May 16, 2011 in the Lawsuit severing LEH s counterclaims into Cause No. 2010-32561-A, which resulted in a Partial Summary Judgment becoming a final judgment in Blue Dolphin s favor.

(4) Income Taxes

Income tax expense consisted of $20,921 and $4,585 and was related to state income tax for the years ended 2011 and 2010, respectively.

The income tax effects of temporary differences that give rise to significant portions of deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010 are presented below:

	2011	2010
Deferred tax assets:		
Net operating loss and capital loss carryforwards	$ 6,693,850	$ 7,236,636
AMT credit carryforward		11,564
Basis differences in property and equipment	(519,890)	(661,540)
Total deferred tax assets	6,173,960	6,586,660
Less: valuation allowance	(6,173,960)	(6,586,660)
Deferred tax assets, net	$	$

In assessing the recoverability of deferred tax assets, we determine whether it is more likely than not that some portion or all of the deferred tax assets will be realized. A full valuation allowance against our deferred tax asset was recognized at December 31, 2011 and 2010 due to our uncertainty as to the utilization of the deferred tax assets in the foreseeable future. The net change in the total valuation allowance for the year ended December 31, 2011 was a decrease of $412,700 in 2011 and an increase $329,864 in 2010.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Our effective tax rate applicable to continuing operations in 2011 and 2010 is as follows:

	Years Ended December 31, 2011	2010
Expected tax rate	34.00%	(34.00%)
Change in valuation allowance recognized in earnings	(30.73%)	34.42%
	3.27%	0.42%

For federal tax purposes, we had net operating loss carry-forwards (NOLs) of approximately $19.7 million at December 31, 2011. These NOLs must be used prior to their expiration, which will occur between 2018 and 2030.

We adopted the provisions of the ASC guidance on accounting for uncertainty in income taxes. The guidance clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements. The guidance also prescribes 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. The standard also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

The provisions of the guidance on accounting for uncertainty in income taxes have been applied to all of our material tax positions taken for all open tax years on the date of adoption through the fiscal year ended December 31, 2011. We have determined that all of our material tax positions taken in our income tax returns and the positions we expect to take in our future income tax filings meet the more likely-than-not recognition threshold. In addition, we have determined that, based on our judgment, none of these tax positions meet the definition of uncertain tax positions that are subject to the non-recognition criteria set forth in the guidance.

The State of Texas has a business tax that is imposed on gross revenue to replace its prior franchise tax regime. Although the Texas margins tax (TMT) is imposed on an entity s gross revenue rather than on its net income, certain aspects of the tax make it similar to an income tax. In accordance with the accounting guidance, we have properly determined the impact of the TMT in the determination of our reported state current and deferred income tax liability.

As part of this guidance, we record income tax related interest and penalties, if applicable, as a component of the provision for income tax expense. However, there were no amounts recognized relating to interest and penalties in the consolidated statements of operations for the years ended December 31, 2011 and 2010. Furthermore, none of our federal and state income tax returns are currently under examination by the Internal Revenue Service (IRS) or state authorities. As of December 31, 2011, fiscal years 2008 and later remain subject to examination by the IRS and fiscal years 2007 and later remain subject to examination by State of Texas. We believe there are no uncertain tax positions for both federal and state income taxes.

(5) Stock Options

We adopted the 2000 Stock Incentive Plan (the 2000 Plan) effective April 14, 2000, under which we make stock-based compensation awards. In 2007, the number of shares of common stock, par value $0.01 per share (the Common Stock), reserved for grants of incentive stock options (ISOs) and other stock-based awards under the 2000 Plan was increased to 1,200,000 shares. In July 2010, our stockholders approved a 1-for-7 reverse-stock-split of our Common Stock, which reduced the number of shares available for grant under the 2000 Plan from 1,200,000 shares to 171,128 shares. As of December 31, 2011, we had 80,495 shares of Common Stock available for future grants. Options granted under the 2000 Plan have contractual terms ranging

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

from six to ten years. The exercise price of ISOs cannot be less than 100% of the fair market value of a share of our Common Stock as determined on the grant date. With the exception of certain ISOs granted in 2007 and 2008, all ISO awards vested immediately. Specifically, 200,000 ISOs granted in May 2007 and 75,000 ISO s granted in August 2008 have a three year vesting period and 150,000 ISOs granted in October 2007 have a two year vesting period. An additional 28,500 options were granted in October 2007 that vested immediately. Although the 2000 Plan provides for the granting of other incentive awards, only ISOs and non-statutory stock options have been issued under the 2000 Plan. The 2000 Plan is administered by the Compensation Committee of the Board.

Subsequent to the year ended December 31, 2011, our stockholders approved two amendments to the 2000 Plan: (i) resetting the expiration date from April 14, 2010 to April 14, 2020 and (ii) increasing the number of shares of Common Stock available for issuance from 171,128 shares to 1,000,000 shares.

We are permitted a corporate income tax deduction for certain stock options that are exercised by our employees. The corporate income tax deduction is the amount of income recognized by the employee as a result of exercising the stock option. The income tax benefit, when taken, is shown on our Consolidated Statement of Cash Flows as financing cash inflows. For the foreseeable future, any tax deductions we receive from the exercise of stock options will be applied to the valuation allowance in determining our net operating loss carry forward.

Additionally, we used the alternate transition method (simplified method) for calculating the beginning balance in the pool of excess tax benefits in accordance with ASC s guidance on transition election related to accounting for the tax effects of share-based payment awards.

We estimate the fair value of stock options granted on the date of grant using the Black-Scholes-Merton option-pricing model. There were no options granted during the years ended December 31, 2011 and 2010. Expected volatility when used in the model is based on the historical volatility of our Common Stock and is weighted 50% for the historical volatility over a past period equal to the expected term and 50% for the historical volatility over the previous two years prior to the grant date.

The expected term of options granted used in the model represents the period of time that options granted are expected to be outstanding. The method used to estimate the expected term is the simplified method as allowed under the provisions of SEC Staff Accounting Bulletin No. 107. This number is calculated by taking the average of the sum of the vesting period and the original contract term. The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the date of the grant. As we have not declared dividends on our Common Stock since we became a public entity, no dividend yield is used. No forfeiture rate is assumed due to the forfeiture history for this type of award. Actual value realized, if any, is dependent on the future performance of our Common Stock and overall stock market conditions. There is no assurance that the value realized by an optionee will be at or near the value estimated by the Black-Scholes-Merton option-pricing model.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

At December 31, 2011, there were a total of 28,887 shares of Common Stock reserved for issuance upon exercise of outstanding options under the 2000 Plan. A summary of the status of our stock options granted to key employees, officers and directors, for the purchase of shares of Common Stock, is as follows:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Options outstanding at December 31, 2009	60,645	$ 17.69		
Options granted		$ 0.00		
Options exercised		$ 0.00		
Options expired or cancelled	(30,255)	$ 22.10		
Options outstanding at December 31, 2010	30,390	$ 13.29	2.8	$
Options granted		$ 0.00		
Options exercised		$ 0.00		
Options expired or cancelled	(1,503)	$ 13.30		
Options outstanding at December 31, 2011	28,887	$ 13.29	1.9	
Options exercisable at December 31, 2011	28,887	$ 13.29	1.9	$

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

The following table summarizes additional information about stock options outstanding at December 31, 2011:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$2.45 to $5.60	10,118	1.3	$ 3.06	10,118	$ 3.06
$10.85 to $13.30	1,843	0.2	$ 10.85	1,843	$ 10.85
$19.67	16,926	2.4	$ 19.67	16,926	$ 19.67
	28,887			28,887	

The following summarizes the net change in non-vested stock options for the years shown:

	Shares	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2009	9,714	$ 16.46
Granted		$ 0.00
Canceled or expired		$ 0.00
Vested	(9,714)	$ 16.46
Non-vested at December 31, 2010		$ 0.00
Granted		$ 0.00
Canceled or expired		$ 0.00
Vested		$ 0.00
Non-vested at December 31, 2011		$ 0.00

As of December 31, 2011, there was no unrecognized compensation cost related to non-vested stock options granted under the 2000 Plan.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

(6) Leases

We have various operating leases that extend through 2013. The following is a schedule of future minimum lease payments under non-cancelable operating leases exceeding one year at December 31, 2011:

Years Ending December 31,	Future Minimum Lease Payments
2012	137,874
2013	480
	$ 138,354

Rent expense on operating leases for the years indicated are as follows:

Years Ended December 31,	Lease Expense
2011	$ 113,585
2010	$ 115,837

(7) Commitments and Contingencies

We are involved in various claims and legal actions arising in the ordinary course of business. In our opinion, the ultimate disposition of these matters will not have a material effect on our consolidated financial position, results of operations or cash flows.

(8) Business Segment Information

At December 31, 2011, our operations were conducted in two business segments: (i) pipeline transportation services and (ii) oil and gas exploration and production. These segments were managed jointly due to our size. We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments, which consist of our consolidated businesses and investments. We believe EBIT is useful to our investors because it allows them to evaluate our operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income or loss from continuing operations, such as the impact of accounting changes, (ii) income taxes and (iii) interest expense (income). We exclude interest expense (income) and other expense or income not pertaining to the operations of our segments from this measure so that investors may evaluate our current operating results without regard to our financing methods or capital structure. We understand that EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating cash flows.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Below is a reconciliation of our EBIT (by segment) for each of the years ended December 31, 2011 and 2010:

	Year Ended December 31, 2011			
	Segment			
	Pipeline Transportation	Oil and Gas Exploration & Production	Corporate & Other[1]	Total
Revenues	$ 931,500	$ 1,342,718	$	$ 2,274,218
Operation cost[2]	1,591,617	1,848,013	449,535	3,889,165
Impairment expense		252,706		252,706
Depletion, depreciation and amortization	380,248	205,826	5,853	591,927
EBIT	$ (1,040,365)	$ (963,827)	$ (455,388)	$ (2,459,580)
Capital expenditures	$ 8,105	$ 184,828	$ 53,561	$ 246,494
Identifiable assets[3]	$ 4,454,500	$ 1,461,740	$ 492,721	$ 6,408,961

(1) Includes unallocated G&A costs associated with corporate maintenance costs and legal expenses. It also includes as identifiable assets corporate available cash of $0.1 million.
(2) Allocable G&A costs are allocated based on revenue.
(3) Identifiable assets contain related legal obligations of each segment including cash, accounts receivable and payable and recorded net assets.

	Year Ended December 31, 2010			
	Segment			
	Pipeline Transportation	Oil and Gas Exploration & Production	Corporate & Other[1]	Total
Revenues	$ 1,878,886	$ 862,685	$	$ 2,741,571
Operation cost[2]	1,943,216	1,013,575	417,131	3,373,922
Depletion, depreciation and amortization	418,923	195,438	4,968	619,329
EBIT	$ (483,253)	$ (346,328)	$ (422,099)	$ (1,251,680)
Capital expenditures	$	$ 1,135,802	$ 201,000	$ 1,336,802
Identifiable assets[3]	$ 4,303,719	$ 1,347,628	$ 330,413	$ 5,981,760

(1)

Includes unallocated G&A costs associated with corporate maintenance costs and legal expenses. It also includes as identifiable assets corporate available cash of $0.6 million.

(2) Allocable G&A costs are allocated based on revenue.

(3) Identifiable assets contain related legal obligations of each segment including cash, accounts receivable and payable and recorded net assets.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

We are exposed to concentrations of credit risk as 100% of our customers are within the oil and gas industry. Our customers may be similarly affected by changes in economic, regulatory or other factors. Trade receivables are generally not collateralized. However, our customers historical and future credit positions are thoroughly analyzed prior to extending credit. Revenue from customers exceeding 10% of our total revenue was as follows for the periods indicated:

	Oil and Gas Sales	Pipeline Operations	Customer Total	% of Total Revenue
Year Ended December 31, 2011:				
Blue Sky	$ 1,222,378	$	$ 1,222,378	54%
Year Ended December 31, 2010:				
Blue Sky	$ 720,348	$	$ 720,348	26%
W&T Offshore	$	$ 557,419	$ 557,419	20%
Maritech Resources	$ 48,194	$ 296,921	$ 345,115	12%

(9) Disposition of Assets

Pursuant to an Asset Purchase Agreement, BDPL sold its eighty-three and one-third percent (83 1/3%) undivided interest in the Buccaneer Pipeline, as well as some related assets, to Sunoco for proceeds of approximately $3.6 million in cash. The transaction closed on August 3, 2011.

(10) Subsequent Events

Acquisition of LE. As previously reported, we entered into a Purchase and Sale Agreement (the PSA) with LEH and LEH s wholly-owned subsidiaries to acquire one hundred percent (100%) of the issued and outstanding membership interests of LE. LE s primary asset is the 56-acre Nixon Crude Oil Processing Facility (the Nixon Facility).

On February 15, 2012, we acquired LE and issued, in reliance on the exemption provided by Section 4(2) of the Securities Act of 1933, as amended (the Securities Act), 8,393,560 shares of Common Stock, subject to anti-dilution adjustments, to LEH as consideration for LE (the Original BDEC Shares). Additionally, on February 21, 2012, pursuant to the anti-dilution provisions contained in the PSA, and in reliance on the exemption provided by Section 4(2) of the Securities Act, we issued 32,896 shares of Common Stock to LEH (the Anti-Dilution Shares and together with the Original BDEC Shares, the BDEC Shares) effective February 15th, 2012. As a result of our issuance of the BDEC Shares, LEH currently owns eighty percent (80%) of our issued and outstanding Common Stock. The issuance of the BDEC Shares to LEH resulted in a change in control of Blue Dolphin. Further, pursuant to the terms of the Purchase and Sale Agreement, the composition of the Board and management changed. See our Current Reports on Form 8-K filed with the Securities and Exchange Commission on July 22, 201, February 2, 2012, February 21, 2012, February 28, 2012 and March 14, 2012, for more information on the Acquisition.

Management of Blue Dolphin s Assets. As part of LEH s assignment of the membership interests of LE, on February 15, 2012, Blue Dolphin, LE and LEH entered into a Management Agreement (the Management Agreement) pursuant to which LEH agreed to manage and operate the Nixon Facility and Blue Dolphin s other operations (collectively, the Services). Pursuant to the terms of the Management Agreement, LEH shall retain, as compensation for the Services, the right to receive (i) weekly payments based on revenues from the sale of diesel blend stocks processed by the Nixon Facility not to exceed $750,000 per month, (ii) reimbursement for certain accounting

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

costs related to the preparation of LE s financial statements not to exceed $50,000 per month, (iii) $0.25 for each barrel processed at the Nixon Facility during the term of the Management Agreement, up to a maximum quantity of 10,000 barrels per day determined on a monthly basis, and (iv) $2.50 for each barrel processed at the Nixon Facility during the term of the Management Agreement, to the extent the quantity exceeds 10,000 barrels per day determined on a monthly basis. We further agreed to reimburse LEH at cost for all reasonable expenses incurred while performing the Services. All compensation owed to LEH under the Management Agreement is to be paid to LEH within 30 days of the end of each calendar month. The Management Agreement expires upon the earliest to occur of (a) the date of the termination of the Joint Marketing Agreement between LE and a third party dated August 12, 2011, which has an initial term of three years and year-to-year renewals at the option of either party thereafter, (b) August 12, 2014, or (c) upon written notice of either party to the Management Agreement of a material breach of the Management Agreement by the other party. If the Management Agreement is renewed after the expiration of its initial term, then it will thereafter be reviewed on an annual basis by the Board and may be terminated if the Board determines that the Management Agreement is no longer in the best interest of Blue Dolphin.

LEH owns approximately eighty percent (80%) of our issued and outstanding Common Stock. Jonathan P. Carroll, our Chief Executive Officer, President, Assistant Treasurer and Secretary, and Tommy L. Byrd, our interim Chief Financial Officer, Treasurer and Assistant Secretary, are also a member and Chief Financial Officer, respectively, of LEH and, as a result may, under certain circumstances, have interests that differ from or conflict with our interests. Further, pursuant to the Management Agreement, LEH manages and operates the Nixon Facility and Blue Dolphin s other operations. As a result of their relationship with LEH, Messrs. Carroll and Byrd may experience conflicts of interest in the execution of their duties on behalf of Blue Dolphin including with respect to the Management Agreement. See Part I, Item 1A. Risk Factors of this report related to related party transactions.

Lazarus Energy Development, LLC (LED) Acquisition. Pursuant to the terms of the PSA, we had the option to acquire all of the issued and outstanding membership interests of LED, a Delaware limited liability company and a wholly-owned subsidiary of LEH. Among other assets, LED holds approximately 46 acres of real property adjacent to the Nixon Facility. On February 7, 2012, we paid LEH a refundable deposit of approximately $183,000 to exercise the option and as partial payment of the purchase price for LED. As part of the acquisition, we agreed to assume an LED loan in the amount of $1.5 million collateralized by the real property adjacent to the Nixon Facility. We expect to complete the acquisition of LED from LEH in the first half of 2012 for a total purchase price of approximately $1.68 million. See Part I, Item 1A. Risk Factors of this report related to acquisition opportunities, as well as Liquidity and Capital Resources under Part II, Item 7 of this report for additional information on how we plan to fund the acquisition of LED.

(11) Supplemental Oil and Gas Information (Unaudited)

The following supplemental information regarding our oil and gas activities is presented pursuant to the disclosure requirements promulgated by the SEC and the FASB.

Associated with our non-operating interest in the North Sumatra Basin-Langsa Field, we recognized gas and oil sales revenue of approximately $1,222,400 and $720,300 in 2011 and 2010, respectively, and lease operating expenses of approximately $1,098,500 and $601,200 in 2011 and 2010, respectively. We have a working interest of 7.0% and a net revenue interest of 5.20625%, subject to reversion, in the oil field.

Associated with our non-operating interest in High Island Block 115, we recognized gas and oil sales revenue of approximately $84,200 and $48,900 in 2011 and 2010, respectively, and lease operating expenses of approximately $35,100 and $32,900 in 2011 and 2010, respectively. We have a working interest of 2.5% and a net revenue interest of 2.008% in one zone of a single well in the lease.

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Associated with our non-operating interest in Galveston Area Block 321, we recognized gas and oil sales revenue of approximately $26,900 and $48,200 in 2011 and 2010, respectively. We did not incur lease operating expenses in 2011 and 2010. We have an overriding royalty interest of 0.5% in an exploratory well in the lease.

Associated with our non-operating interest in High Island Block 37, we recognized gas and oil sales revenue of approximately $9,200 and $45,300 in 2011 and 2010, respectively, and lease operating expenses of approximately $27,500 and $39,500 in 2011 and 2010, respectively. We have a working interest of 2.88% and a net revenue interest of 2.246% in the block.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

We retained independent petroleum engineering consulting firms to provide year-end estimates of our future net recoverable oil and natural gas. Estimated proved net recoverable reserves as indicated herein include only those quantities that can be expected to be commercially recoverable. Estimated reserves for the year ended December 31, 2011 were computed using benchmark prices based on the unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas during each month of 2011, as required by SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*, effective December 31, 2009. Costs were estimated using costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods.

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Set forth below is a summary of the changes in the estimated quantities of our crude oil and condensate, and gas reserves for the periods indicated, as estimated by us at December 31, 2011 and 2010. Our reserves are located in the North Sumatra Basin offshore Indonesia and U.S. Gulf of Mexico. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

Proved reserves are estimated quantities of gas, crude oil, and condensate that geological and engineering data demonstrate, with reasonable certainty, are 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.

	Oil (Bbls)	Natural Gas (Mcf)
Quantity of Proved Oil and Gas Reserves		
Total proved reserves at December 31, 2009	758	127,849
Revisions to previous estimates	(232)	59,269
Extensions, discoveries, improved recovery and other additions		
Purchase of reserves in place	139,915	
Sales of reserves in place		
Production	(6,319)	(31,634)
Total proved reserves at December 31, 2010	134,122	155,484
Revisions to previous estimates	(74,684)	(117,100)
Extensions, discoveries, improved recovery and other additions	131,040	
Purchase of reserves in place		
Sales of reserves in place		
Production	(7,904)	(25,454)
Total proved reserves at December 31, 2011	182,574	12,930
Proved developed reserves:		
December 31, 2011	31,564	12,930
December 31, 2010	30,171	155,484
Total proved reserves:		
December 31, 2011	182,574	12,930
December 31, 2010	134,122	155,484

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Capitalized Costs of Oil and Gas Producing Activities

The following table sets forth the aggregate amounts of capitalized costs relating to our oil and gas producing activities and the aggregate amount of related accumulated depletion, depreciation, amortization as of:

	December 31, 2011	December 31, 2010
Unproved properties and prospect generation costs not being amortized	$	$
Proved properties being amortized	2,321,913	2,222,535
Total capitalized costs	2,321,913	2,222,535
Accumulated depreciation, depletion and amortization	(1,269,305)	(1,063,480)
Net capitalized costs	$ 1,052,608	$ 1,159,055

Costs Incurred in Oil and Gas Producing Activities

The following table reflects the costs incurred in oil and gas property acquisition, disposition, exploration and development activities during the periods indicated:

	Years Ended December 31, 2011	Years Ended December 31, 2010
Costs incurred:		
Acquisition of proved properties	$	$ 685,714
Acquisition of unproved properties		
Exploration costs		58,719
Development costs	184,828	
Total costs incurred	$ 184,828	$ 744,433

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Results of Operations for Oil and Gas Producing Activities

The results of operations from oil and gas producing activities below exclude non-oil and gas revenue, general and administrative expenses, interest expense and interest income.

	Years Ended December 31, 2011	2010
Revenues from oil and gas producing activities	$ 1,342,718	$ 862,685
Production costs	(1,174,252)	(673,768)
Depreciation, depletion, and amortization	(205,825)	(195,438)
Impairment of oil and gas properties	(252,706)	
Pretax income from producing activities	(290,065)	(6,521)
Income tax expense/estimated loss carryforward benefit	4,583	103
Results of oil and gas producing activities (excluding corporate overhead and interest costs)	$ (285,482)	$ (6,418)

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The following table reflects the Standardized Measure of Discounted Future Net Cash Flows relating to our interest in proved oil and gas reserves for:

	Years Ended December 31, 2011	2010
Future cash inflows	$ 21,046,360	$ 11,449,829
Future development costs	(2,333,450)	(700,000)
Future production costs	(7,329,560)	(3,165,036)
Future dismantlement and abadonment costs	(573,600)	
Future income taxes		
10% discount factor	(1,482,310)	(2,219,392)
Standardized measure of discounted future net cash inflows (outflows)	$ 9,327,440	$ 5,365,401

Future net cash flows at each year end, as reported in the above schedule, were determined by summing the estimated annual net cash flows computed by: (i) multiplying estimated quantities of proved reserves to be produced during each year by year-end prices and (ii) deducting estimated expenditures to be incurred during each year to develop and produce the proved reserves (based on year-end costs).

Table of Contents

Index to Financial Statements

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Income taxes were computed by applying year-end statutory rates to pretax net cash flows, reduced by the tax basis of the properties and available net operating loss carry-forwards. The annual future net cash flows were discounted, using a prescribed 10% rate, and summed to determine the standardized measure of discounted future net cash flow.

We caution readers that the standardized measure information which places a value on proved reserves is not indicative of either fair market value or present value of future cash flows. Other logical assumptions could have been used for this computation which would likely have resulted in significantly different amounts. Such information is disclosed solely in accordance with authoritative guidance and the requirements promulgated by the SEC to provide readers with a common base for use in preparing their own estimates of future cash flows and for comparing reserves among companies. We do not rely on these computations when making investment and operating decisions. Principal changes in the Standardized Measure of Discounted Future Net Cash Flows attributable to our proved oil and gas reserves for the periods indicated are as follows:

	Years Ended December 31,	
	2011	2010
Beginning balance	$ 5,365,401	$ 336,296
Sales and transfers, net of production costs	(168,466)	(188,917)
Net change in sales and transfer prices, net of production costs	2,258,537	421,761
Extension, discoveries and improved recovery, net of future production and development costs	7,301,830	
Development costs incurred during the period that reduced future development costs	(56,967)	(45,500)
Changes in estimated future development cost	(544,099)	(32,186)
Revisions of quantity estimates	(3,293,469)	(39,618)
Accretion of discount	(536,540)	33,630
Net change in income taxes		
Change in production rates (timing) and other	(998,787)	4,879,935
Net change	3,962,039	5,029,105
Ending balance	$ 9,327,440	$ 5,365,401

Table of Contents

Index to Financial Statements

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the year covered by this report, we carried out an evaluation under the supervision and with the participation of our management, including our Principal Executive Officer and our Principal Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based upon this evaluation, as of December 31, 2011, the Principal Executive Officer and Principal Financial Officer concluded that our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act, are recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and that such information is accumulated and communicated to our management, including the Principal Executive Officer and Principal Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management s Annual 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-5(f) under the Exchange Act). Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control Integrated Framework. Our management has concluded that, as of December 31, 2011, our internal control over financial reporting is effective based on these criteria. This annual report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting pursuant to the permanent exemption for smaller reporting companies that permit us to provide only management s report.

Our management, including our Principal Executive Officer and Principal Financial Officer, does not expect our internal control over financial reporting to prevent all error or fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must take into account resource constraints. The benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. Our internal control over financial reporting, however, is designed to provide reasonable assurance that the objectives of internal control over financial reporting are met.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2011, there were no changes in our internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act), that have materially affected, or are reasonably likely to materially affect, the internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

Index to Financial Statements

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 is incorporated by reference to our definitive proxy statement relating to our 2012 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated by reference to our definitive proxy statement relating to our 2012 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by Item 12 is incorporated by reference to our definitive proxy statement relating to our 2012 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 is incorporated by reference to our definitive proxy statement relating to our 2012 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 is incorporated by reference to our definitive proxy statement relating to our 2012 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

Remainder of Page Intentionally Left Blank

Table of Contents

Index to Financial Statements

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES
(a) List of documents filed as part of this report

3. *Exhibits*. We hereby file as part of this Annual Report on Form 10-K the Exhibits listed in the attached Exhibit Index.

No.	Description
3.1	Amended and Restated Certificate of Incorporation of Blue Dolphin. (1)
3.2	Amended and Restated By-Laws of Blue Dolphin. (2)
4.1	Specimen Stock Certificate. (3)
4.2	Form of Promissory Note issued pursuant to the Note and Warrant Purchase Agreement dated September 8, 2004. (4)
4.3	Promissory Note of Lazarus Louisiana Refinery II, LLC, payable to Blue Dolphin dated July 31, 2009. (5)
10.1	Blue Dolphin 2000 Stock Incentive Plan. (6) *
10.2	First Amendment to the Blue Dolphin 2000 Stock Incentive Plan. (7) *
10.3	Second Amendment to the Blue Dolphin 2000 Stock Incentive Plan. (8) *
10.4	Fourth Amendment to the Blue Dolphin 2000 Stock Incentive Plan. (9) *
10.5	Purchase and Sale Agreement by and between Blue Dolphin Pipe Line Company and MCNIC, dated February 1, 2002. (10)
10.6	Sale of American Resources Offshore, Inc. Common Stock Agreement between Blue Dolphin Exploration Co. and Ivar Siem, dated September 8, 2004. (4)
10.7	Purchase and Sale Agreement by and between Blue Dolphin, WBI Pipeline & Storage Group, Inc. and SemGas LP, dated October 29, 2004. (11)
10.8	Amendment to the Asset Purchase Agreement by and among MCNIC Offshore Pipeline and Processing Company and Blue Dolphin Pipe Line Company dated February 28, 2005. (12)
10.9	Placement Agency Agreement by and between Blue Dolphin and Starlight Investments, LLC dated May 27, 2005. (13)
10.10	Form of Stock Purchase Agreement between Blue Dolphin and Osler Holdings Limited, Gilbo Invest AS, Spencer Energy AS, Spencer Finance Corp., Hudson Bay Fund, LP, Don Fogel and SIBEX Capital Fund, Inc. dated March 8, 2006. (14)
10.11	Loan and Option Agreement by and among Lazarus Energy Holdings, LLC, Lazarus Louisiana Refinery II, LLC, Lazarus Energy, LLC, Lazarus Environmental, LLC, and Blue Dolphin dated July31, 2009. (15)
10.12	Sale and Purchase Agreement by and among Blue Dolphin Exploration Company, Blue Sky Langsa Limited and Blue Sky Energy and Power Inc. dated July 21, 2010. (16)

Table of Contents

Index to Financial Statements

10.13	Option Agreement by and among Blue Dolphin Exploration Company, Blue Sky Langsa Limited and Blue Sky Energy and Power Inc. dated July 21, 2010. [17]
10.14	Purchase and Sale Agreement dated July 12, 2011 by and among Blue Dolphin, Lazarus Energy Holdings, LLC, Lazarus Louisiana Refinery II, LLC, Lazarus Texas Refinery II, LLC, Lazarus Environmental, LLC, Lazarus Energy, LLC and Lazarus Energy Development, LLC. [18]
10.15	Asset Purchase Agreement by and among Sunoco Partners Marketing & Terminals L.P. and Blue Dolphin Pipe Line Company and Bitter Creek Pipelines, LLC dated August 3, 2011.**
10.16	Management Agreement by and between Lazarus Energy Holdings, LLC, Lazarus Energy, LLC and Blue Dolphin effective as of February 15, 2012. [19]
14.1	Code of Ethics applicable to the Chairman, Chief Executive Officer and Senior Financial Officer. [20]
21.1	List of Subsidiaries of Blue Dolphin. **
23.1	Consent of UHY LLP. **
23.2	Consent of American Energy Advisors, Inc. **
23.3	Consent of Lonquist & Co., LLC. **
31.1	Jonathan P. Carroll Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002. **
31.2	Tommy L. Byrd Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002. **
32.1	Jonathan P. Carroll Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002. **
32.2	Tommy L. Byrd Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002. **
99.1	Report of American Energy Advisors, Inc., Petroleum Engineer Consultant. **
99.2	Report of Lonquist & Co. LLC, Petroleum Engineer Consultant. **
101.INS	XBRL Instance Document.**
101.SCH	XBRL Taxonomy Schema Document.**
101.CAL	XBRL Calculation Linkbase Document.**
101.LAB	XBRL Label Linkbase Document.**
101.PRE	XBRL Presentation Linkbase Document.**
101.DEF	XBRL Definition Linkbase Document.**

* Management Compensation Plan.
** Filed herewith
(1) Incorporated herein by reference to Exhibit 3.1 filed in connection with the Form 8-K of Blue Dolphin under the Exchange Act dated June 2, 2009 (Commission File No. 000-15905).
(2) Incorporated herein by reference to Exhibit 3.1 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated December 26, 2007 (Commission File No. 000-15905).
(3) Incorporated herein by reference to exhibits filed in connection with Form 10-K of Blue Dolphin for the year ended December 31, 1989 under the Exchange Act dated March 30, 1990 (Commission File No. 000-15905).
(4) Incorporated herein by reference to Exhibit 10.4 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated September 14, 2004 (Commission File No. 000-15905).

Table of Contents

Index to Financial Statements

(5) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated August 6, 2009 (Commission File No. 000-15905).
(6) Incorporated herein by reference to Appendix 1 filed in connection with the Proxy Statement of Blue Dolphin under the Exchange Act dated April 20, 2000 (Commission File No. 000-15905).
(7) Incorporated herein by reference to Appendix B filed in connection with the definitive Proxy Statement of Blue Dolphin under the Exchange Act dated April 16, 2003 (Commission File No. 000-15905).
(8) Incorporated herein by reference to Appendix A filed in connection with the definitive Proxy Statement of Blue Dolphin under the Exchange Act dated April 27, 2006 (Commission File No. 000-15905).
(9) Incorporated herein by reference to Exhibit B filed in connection with the definitive Proxy Statement of Blue Dolphin under the Exchange Act dated December 28, 2011 (Commission File No. 000-15905).
(10) Incorporated herein by reference to Exhibit 10.20 filed in connection with Form 10-KSB of Blue Dolphin under the Exchange Act dated March 21, 2003 (Commission File No. 000-15905).
(11) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated November 3, 2004 (Commission File No. 000-15905).
(12) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated March 3, 2005 (Commission File No. 000-15905).
(13) Incorporated herein by reference to Exhibit 10.9 filed in connection with Form 10-KSB of Blue Dolphin for the year ended December 31, 2005 under the Exchange Act dated March 30, 2006 (Commission File No. 000-15905).
(14) Incorporated herein by reference to Exhibit 10.10 filed in connection with Form 10-KSB of Blue Dolphin for the year ended December 31, 2005 under the Exchange Act dated March 30, 2006 (Commission File No. 000-15905).
(15) Incorporated herein by reference to Exhibit 10.2 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated August 6, 2009 (Commission File No. 000-15905).
(16) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated July 21, 2010 (Commission File No. 000-15905).
(17) Incorporated herein by reference to Exhibit 10.2 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated July 21, 2010 (Commission File No. 000-15905).
(18) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Exchange Act dated July 22, 2011 (Commission File No. 000-15905).
(19) Incorporated herein by reference to Exhibit 10.2 filed in connection with Amendment No. 1 to Form 8-K of Blue Dolphin under the Exchange Act dated March 14, 2012 (Commission File No. 000-15905).
(20) Incorporated herein by reference to Exhibit 14.1 filed in connection with Form 10-KSB of Blue Dolphin for the year ended December 31, 2004 under the Exchange Act dated March 25, 2005 (Commission File No. 000-15905).

Table of Contents

Index to Financial Statements

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.

BLUE DOLPHIN ENERGY COMPANY

(Registrant)

By: /s/ JONATHAN P. CARROLL
Jonathan P. Carroll
Chief Executive Officer, President
Assistant Treasurer and Secretary
(Principal Executive Officer)

Date: March 30, 2012

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/ JONATHAN P. CARROLL Jonathan P. Carroll	Chief Executive Officer, President, Assistant Treasurer and Secretary (Principal Executive Officer)	March 30, 2012
/s/ TOMMY L. BYRD Tommy L. Byrd	Interim Chief Financial Officer, Treasurer and Assistant Secretary (Principal Financial Officer)	March 30, 2012
/s/ IVAR SIEM Ivar Siem	Chairman of the Board, Director	March 30, 2012
/s/ LAURANCE N. BENZ Laurence N. Benz	Director	March 30, 2012
/s/ JOHN N. GOODPASTURE John N. Goodpasture	Director	March 30, 2012
/s/ A. HAAG SHERMAN A. Haag Sherman	Director	March 30, 2012
/s/ HERBERT N. WHITNEY Herbert N. Whitney	Director	March 30, 2012