BLUE DOLPHIN ENERGY CO
Form 10-K
March 31, 2011

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

or

o **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	NASDAQ Capital Market

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 o No þ

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 o No þ

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 o No o

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ
Aggregate market value of voting stock held by non-affiliates of the registrant as of June 30, 2010 was approximately $2.7 million based on the reverse stock split-adjusted closing price of $2.47 per share on the NASDAQ Capital Market.

Number of shares of Common Stock outstanding as of March 31, 2011	2,078,514

DOCUMENTS INCORPORATED BY REFERENCE

Certain sections of the registrant s definitive proxy statement for its 2011 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, 2010, are incorporated by reference in Part III of this report.

BLUE DOLPHIN ENERGY COMPANY
FORM 10-K REPORT INDEX

Table of Contents

PART I

<u>Forward Looking Statements</u>. Certain of the statements included in this annual report on Form 10-K, including those regarding future financial performance or results or that are not historical facts, are forward-looking statements as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. The words expect, plan, believe, anticipate, project, estimate, and similar expressions are intended to identify forward-looking statements. Blue Dolphin Energy Company (referred to herein, with its predecessors and subsidiaries, as Blue Dolphin, we, us and our) cautions readers that these statements are not guarantees of future performance or results and such statements involve risks and uncertainties that may cause actual results and outcomes to differ materially from those indicated in forward-looking statements. Some of the important factors, risks and uncertainties that could cause actual results to vary from forward-looking statements include:

- *ability to continue as a going concern;*
- *collectability of a $2.0 million loan receivable, net of credited and recovered amounts;*
- *ability to complete a combination with one or more target businesses;*
- *ability to secure additional working capital to fund operations;*
- *ability to monetize our pipeline assets;*
- *ability to improve pipeline utilization levels;*
- *performance of third party operators for properties where we have an interest;*
- *production from oil and gas properties that we have interests in;*
- *volatility of oil and gas prices;*
- *uncertainties in the estimation of proved reserves, in the projection of future rates of production, the timing of development expenditures and the amount and timing of property abandonment;*
- *costly changes in environmental and other government regulations for which we are subject;*
- *adverse changes in the global financial markets; and*
- *potential delisting of our Common Stock by NASDAQ due to non-compliance with NASDAQ listing requirements.*

Additional factors that could cause actual results to differ materially from those indicated in the forward-looking statements are discussed in Item 1A Risk Factors. Readers are cautioned not to place undue reliance on these forward-looking statements which speak only as of the date hereof. We undertake no duty to update these forward-looking statements. Readers are urged to carefully review and consider the various disclosures made by us which attempt to advise interested parties of the additional factors which may affect our business, including the disclosures made under the caption Management s Discussion and Analysis of Financial Condition and Results of Operations in this report.

ITEM 1. BUSINESS

The Company

Blue Dolphin, a Delaware corporation, was formed in 1986 as a holding company and conducts substantially all of its operations through its subsidiaries. We are engaged in two lines of business: (i) pipeline transportation services to producers/shippers, and (ii) oil and gas exploration and production. Substantially all of our assets consist of equity interests in our subsidiaries. Our operating subsidiaries are:

Blue Dolphin Pipe Line Company, a Delaware corporation;

Blue Dolphin Petroleum Company, a Delaware corporation;

Blue Dolphin Exploration Company, a Delaware corporation;

Blue Dolphin Services Co., a Texas corporation; and

Petroport, Inc., a Delaware corporation.

Table of Contents

Our principal executive office is located at 801 Travis Street, Suite 2100, Houston, Texas, 77002, and our telephone number is (713) 568-4725. We have five (5) full-time employees and regularly use the services of two (2) consultants. Our common stock, par value $0.01 per share (Common Stock) is publicly traded on the NASDAQ Capital Market under the ticker symbol BDCO. Our 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

NASDAQ Listing. On March 16, 2010, we were notified by NASDAQ that our Common Stock was subject to delisting for failure to comply with the minimum bid price listing requirement. On April 15, 2010, we submitted a compliance plan, which outlined a reverse stock split, to a NASDAQ Listing Qualifications Panel (the Panel) for meeting the minimum bid requirement. As permitted under NASDAQ s listing rules, on May 14, 2010, the Panel granted us an extension for continued listing until compliance with the minimum bid requirement was fully demonstrated. On August 4, 2010, following the effectiveness of our reverse stock split, we received confirmation from NASDAQ that we had cured our minimum bid price deficiency.

On May 20, 2010, we were notified by NASDAQ that our stockholders equity had fallen below the minimum listing requirement. On May 27, 2010, we submitted a compliance plan to the Panel to cure the stockholders equity deficiency. The compliance plan provided a pro forma calculation of the impact of our working interest in the North Sumatra Basin-Langsa Field, as well as outlined our efforts to collect on an outstanding loan receivable. As permitted under NASDAQ Listing Rules, on June 23, 2010, the Panel granted us an extension for continued listing until compliance with the stockholders equity requirement was fully demonstrated. On November 24, 2010, we received confirmation from NASDAQ that we had cured our stockholders equity deficiency. The Panel will monitor our continued compliance with the stockholders equity rule for a period of one year. In the event we fall out of compliance during the monitoring period, the Panel may, at its discretion, delist our Common Stock.

Reverse Stock Split. On March 16, 2010, our Board of Directors (the Board) approved and authorized, subject to stockholder approval, implementation of a reverse stock split of our 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 reverse stock split was approved by our stockholders on June 9, 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, was paid in cash at fair market value. 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 condensed consolidated financial statements have been restated, where applicable, to give retroactive effect of the reverse stock split.

Outstanding Loan Receivable. In the second quarter of 2010, we began foreclosure proceedings on the collateral and guaranty securing a $2.0 million loan, net of credited and recovered amounts (the Loan), made to Lazarus Louisiana Refinery II, LLC (LLRII or the Borrower). The Loan, made on July 31, 2009 and due on January 31, 2010, is secured by (i) a first lien on property owned by Lazarus Environmental, LLC (LEN), (ii) a second lien on property owned by LLRII (collectively the Collateral) and (iii) a guaranty from Lazarus Energy Holdings, LLC (LEH) (the Guaranty). Although we agreed to forbear repayment of the loan receivable until June 11, 2010, the Borrower failed to satisfy certain conditions set forth in the forbearance agreement. When the Loan became due and payable under the original terms, the Borrower defaulted.

Blue Dolphin v. LLRII (State of Louisiana). The Collateral went up for auction under a Writ of Seizure and Sale issued by the 31st Judicial District Court, Parish of Jefferson Davis, State of Louisiana on July 28, 2010. There were no bidders on the property owned by LLRII. As a credit bid against the Loan, we bid the minimum amount of $134,000 for the property owned by LEN, which consisted primarily of an inactive salt water disposal well. As there were no third-party bidders on the property owned by LEN, we acquired the property at the fair market value of $201,000.

Blue Dolphin v. LEH (State of Texas). On May 26, 2010, we filed a petition in the 129th Judicial District, in the District Court of Harris County, State of Texas (the Court) alleging breach of contract and asserting our right to the unpaid principal balance and all accrued interest due and payable under the Loan. Although LEH filed a counter-claim alleging usurious interest based on a $500,000 consulting agreement made between the parties, in September 2010 we exercised our right to cure the alleged usury without having to admit guilt based on a statutory provision. In so doing, the Borrower was credited $500,000 against the outstanding principal balance, and the matter proceeded without undue delay. In response, LEH filed an amended counter-claim further alleging breach of contract under the confidentiality agreement between the parties. By order dated February 7, 2011, the Court granted a partial summary judgment on liability under the promissory note and Guaranty in favor of Blue Dolphin and against LEH and LLRII. The Court, however, deferred a ruling on the damages and attorney s fees to be awarded. Although the parties reached an agreement regarding the amount of attorneys fees to be awarded, and the defendants do not dispute the calculation of damages sought by Blue Dolphin, the defendants continue to contest Blue Dolphin s entitlement to summary judgment. On February 25, 2011, we filed a motion for entry of the partial summary judgment. On March 28, 2010, our motion for entry of the partial summary judgment was heard before the Court. The Court entered the partial summary judgment in the amount of $1.7 million in favor of Blue Dolphin and against LEH and LLRII on the promissory note and Guaranty. The only claim that remains pending is the counter-claim alleging breach of contract under the confidentiality agreement.

Blue Sky Langsa Purchase. In June 2010, we signed a commitment letter with Blue Sky Langsa, Ltd. (Blue Sky) to acquire a 70% working interest in a Technical Assistance Contract for the Langsa area, offshore Indonesia (the North Sumatra Basin-Langsa Field). During the third quarter of 2010, the parties amended the terms of the commitment letter in order to carry out the transaction in two phases. Under the first phase, we acquired a 7% working interest in the North Sumatra Basin-Langsa Field under a definitive sale and purchase agreement dated July 21, 2010. The consideration paid by Blue Dolphin was 342,857 shares of Common Stock on a post reverse stock split adjusted basis. We had the option to acquire the remaining 63% working interest in the North Sumatra Basin-Langsa Field for an additional 3,085,714 shares of Common Stock on a post reverse stock split adjusted basis. We elected not to exercise the option, which expired on September 30, 2010.

Growth Strategy

Historically focused on exploration and production, we sold substantially all of our producing and gas properties in 2002 to satisfy working capital needs and to finance future asset acquisitions, primarily related to our pipeline transportation business. Due to changes in the current economic environment, over the past year and a half we began shifting our strategy from pipeline operations and activities back to focusing more on exploration and production opportunities in an effort to find a more favorable business mix, increase our reserves and improve operational income. Our strategy shift includes expansion into new geographic areas, both on and offshore, while pursuing a balanced growth strategy employing varying elements of exploration, development and acquisition activities.

Current throughput on our active pipelines is significantly below capacity. As future utilization is dependent upon the success of drilling programs around our pipelines and the attraction of new and retention of existing producers/shippers operating in the area, we are evaluating options to monetize our pipeline assets. Options may include the sale of a portion or all of our ownership interest in our pipeline assets or a joint venture to jointly develop terminal projects based on a capital expenditure and revenue sharing formula.

See Note (8), Business Segment Information, in the Notes to Consolidated Financial Statements for additional information on revenue, operating income (loss), assets and depreciation, depletion and amortization on our business segments.

Pipeline Operations

We market our gathering and transportation services to producers/shippers operating in the vicinity of our pipelines, which are located offshore and onshore in the Texas Gulf Coast area. The fees we charge are based on the producer s/shipper s anticipated oil and gas throughput volumes, as well as their intended usage of our onshore facilities. All of our pipeline assets are held in and the operations conducted by Blue Dolphin Pipe Line Company. Unless otherwise stated herein, all gas liquid volumes transported are attributable to production from third party producers/shippers.

Pipeline Assets. The following provides a pipeline segment summary:

Pipeline Segment	Market	Ownership	Miles of Pipeline	Capacity (MMcf/d)	Storage (Bbls)	Average Throughput (MMcf/d)		
						2010	2009	2008
BDPS[1]	Gulf of Mexico	83.3%	38	180	85,000	13.7	15.5	22.6
GA 350	Gulf of Mexico	83.3%	13	65		17.4	19.0	23.8
Omega[2]	Gulf of Mexico	83.3%	18	110				

(1) The BDPS includes the Blue Dolphin Pipeline, an offshore platform, the Buccaneer Pipeline, onshore facilities for oil and gas separation and dehydration, 85,000 Bbls of above-ground tankage for storage of crude oil and condensate, a barge loading terminal on the Intracoastal Waterway and 360 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. 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. After processing, the gas is transported to an end user and a major intrastate pipeline system with further downstream tie-ins to other intrastate and interstate pipeline systems and end users. The Blue Dolphin Pipeline, which is a component of the BDPS, consists of two segments, an offshore segment and an onshore segment. The offshore segment transports both oil and gas and is comprised of approximately 34 miles of 20-inch pipeline originating at an offshore platform in Galveston Area Block 288 and running to shore. The offshore segment also includes the platform in Galveston Area Block 288 and 5 field gathering lines totaling approximately 27 miles connected to the main 20-inch line. An additional 2 miles of 20-inch pipeline onshore connects the offshore segment to the onshore facility at Freeport, Texas. The onshore segment also includes approximately 2 miles of 16-inch pipeline for transportation of gas from the onshore facility to a sales point at a chemical plant complex and intrastate pipeline system tie-in in Freeport, Texas. The Buccaneer Pipeline, an approximate 2 mile, 8-inch liquids pipeline, transports crude oil and condensate from the onshore facility storage tanks to our barge-loading terminal on the Intracoastal Waterway near Freeport, Texas for sale to third parties.

(2) Inactive.

Blue Dolphin Pipeline System (BDPS) The BDPS spans approximately 38 miles from Galveston Area Block 288 offshore to our onshore facilities and the Dow Chemical Plant Complex in Freeport, Texas. We own an 83% undivided interest in the BDPS. 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

9 Mcf of gas per day from 7 shippers, which represents 5% of throughput capacity.

<u>*Galveston Area Block 350 Pipeline*</u> *(the GA 350 Pipeline)* The GA 350 Pipeline 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 Pipeline is 65 MMcf of gas per day. We own an 83% undivided interest in the GA 350 Pipeline. The GA 350 Pipeline is currently transporting an aggregate of approximately 14 MMcf of gas per day from 5 shippers, which represents 22% of throughput capacity.

<u>*Omega Pipeline*</u> The Omega Pipeline 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. We own an 83% undivided interest in the Omega Pipeline. The Omega Pipeline is

Table of Contents

currently inactive. Reactivation of the Omega Pipeline 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 in offshore Indonesia. Our leasehold interests, which are held in and the operations conducted by Blue Dolphin Petroleum Company, 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.

Exploration and Production Assets. The following provides an oil and gas property summary:

Field	Operator	Approximate Working / Royalty Interest
U.S. Gulf of Mexico:		
Galveston Area Block 321	Maritech Resources, Inc.	0.5%
High Island Block 115	Rooster Petroleum, LLC	2.5%
High Island Block 37	Hilcorp Energy Company	2.8%
Indonesia:		
North Sumatra Basin-Langsa Field	Blue Sky Langsa, Ltd.	7.0%

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. We own a 0.5% overriding royalty interest in the well. The lease is operated by Maritech Resources. The A-4 Well is currently producing approximately 1.2 MMcf of gas per day and 110 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. We own a 2.5% working interest in a single production zone in the well. The lease is operated by Rooster Petroleum, LLC. The B-1 ST2 Well is currently producing approximately 4.2 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 one active well, the A-2 Well, and one inactive well, the B-1 Well. We own an approximate 2.8% working interest in this lease that covers 5,760 acres. The lease is operated by Hilcorp Energy Company. The A-2 Well is currently producing approximately 0.8 MMcf of gas per day.

North Sumatra Basin-Langsa Field Located in offshore Indonesia, the North Sumatra Basin-Langsa Field covers approximately 77 square kilometers and contains two oil fields in waters less than 325 feet deep. Four wells have been completed in the Malacca Formation one active, the H-4 Well, and three inactive. Production is gathered via a floating production storage and offloading (FPSO) vessel operated by Mitsui Ocean Development & Engineering Co., Ltd. We own a 7.0% working interest in the oil field. The H-4 Well is currently producing approximately 430 barrels of oil per day.

As of December 31, 2010, there were no drilling oriented activities of material importance associated with our exploration and production assets.

Table of Contents

Productive Wells and Acreage. The following table sets forth our ownership interest at December 31, 2010, 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.

Productive Wells

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
U.S. Gulf of Mexico						
Working Interest			2.0	0.1	2.0	0.1
Royalty Interest			1.0	0.1	1.0	0.1
Indonesia						
Working Interest	1.0	0.1			1.0	0.1
	1.0	0.1	3.0	0.2	4.0	0.3

The following table sets forth the approximate developed and undeveloped acreage that we held as leasehold interest at December 31, 2010. 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 and natural gas, regardless of whether or not such acreage contains proved reserves.

Acreage

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

Estimated Proved Reserves and Future Net Cash Flows. Our proved reserve estimates for oil and natural gas were prepared by William J. Driscoll, an independent geologist, in accordance with the generally accepted petroleum engineering and evaluation principles and most recent definitions and guidelines established by the SEC. A copy of Mr. Driscoll s summary reserve report is filed as an exhibit to this report. All reserve definitions contained herein are in accordance with the SEC s Rule 4-10(a)(1)-(32) of Regulation S-X.

The quantities of proved oil and gas reserves presented below 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 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 reserves and the discounted present value of future net revenue attributable thereto.

Table of Contents

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 (9), Supplemental Oil and Gas Information, in the Notes to Consolidated Financial Statements for further information concerning our proved reserves, changes in proved 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 reserves.

Proved Undeveloped Reserves. We had total estimated proved undeveloped reserves of 104 Mbbls and 0 Mbbls as of December 31, 2010 and 2009, respectively. This increase was due to our 2010 acquisition of the North Sumatra Basin-Langsa Field. During 2010, we did not convert any proved undeveloped reserves to proved developed reserves. At December 31, 2010, no material amounts of proved undeveloped reserves remain undeveloped for five years or more after they were initially disclosed as proved undeveloped reserves.

The following table presents the estimates of proved reserves (as hereinafter defined) and the discounted present value of future net revenue or expenses from proved reserves after income taxes to our net interest in oil and gas properties as of December 31, 2010. 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, 2010

	Net Oil Reserves (Mbbls)	Net Gas Reserves (MMcf)	Discounted Present Value of Future Net Cash Inflows (Outflows)(1) (in thousands)
Proved Developed			
Galveston Area Block 321	0.2	9	$ 47
High Island Block 115		131	297
High Island Block 37		15	(48)
North Sumatra Basin-Langsa Field	29.9		276
Total Proved Reserves	30.1	155	$ 572
Proved Undeveloped			
Galveston Area Block 321			$
High Island Block 115			
High Island Block 37			
North Sumatra Basin-Langsa Field	104.0		3,913
Total Proved Developed	104.0		$ 3,913

(1) The estimated present value of future net cash outflows from our proved reserves has been determined by using domestic prices of $79.61 per barrel of oil and $4.33 per Mcf of gas and an international price of $80.35 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 Securities and Exchange Commission (the SEC Method).

Table of Contents

Internal Controls over Reserve Estimates. Our policies regarding internal controls over reserve estimates require reserves to be in compliance with the SEC definitions and guidance and for reserves to be prepared by an independent geologist under the supervision of our Chief Executive Officer. We provided the geologist with estimate preparation material such as property interests, production, current operation costs, current production prices and other information. This information is reviewed by our Chief Executive Officer and Principal Financial and Accounting Officer to ensure accuracy and completeness of the data prior to submission to our third party geologist. A letter which identifies the professional qualifications of the individual who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2010 has been filed as Exhibit 99.1 to this report.

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

	Years Ending December 31,				
	2011	2012	2013	2014	2015
Galveston Area Block 321					
High Island Block A-7	$ 192				
High Island Block 115				$ 38	
High Island Block 37			$ 68		
North Sumatra Basin-Langsa Field					

Remainder of Page Intentionally Left Blank

10

Table of Contents

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 interest for each of the periods indicated.

Net Production, Price and Cost Data

	Years Ended December 31,					
	2010		2009		2008	
	U.S. Gulf of Mexico	Indonesia	U.S. Gulf of Mexico	Indonesia	U.S. Gulf of Mexico	Indonesia
Crude Oil and Condensate:						
Production (Bbls)	250	8,154	250		117	
Revenue	$ 20,377	$ 720,348	$ 17,401	$	$ 14,057	$
Average production per day (Bbls) (*)	0.7	22.3	0.7		0.3	
Average sales price per Bbl	$ 81.51	$ 88.34	$ 69.60	$	$ 120.25	$
Natural Gas:						
Production (Mcf)	31,654		33,630		44,700	
Revenue	$ 121,960	$	$ 108,576	$	$ 526,522	$
Average production per day (Mcf) (*)	86.7		92.1		122.5	
Average sales price per Mcf	$ 3.85	$	$ 3.23	$	$ 11.78	$
NGLs:						
Production (gallons)						
Revenue	$	$	$	$	$	$
Average production per day (gallons) (*)						
Average sales price per gallon	$	$	$	$	$	$
Production Costs (**):						
Per Mcfe:	$ 2.19	$ 12.29	$ 2.71	$	$ 5.36	$

(*) 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 2010, there were no wells drilled or any other exploratory or development activities conducted.

	Wells Drilled, Net Exploratory(1)		
	2010	2009	2008
U.S. Gulf of Mexico			
Productive			
Dry			1
Indonesia			
Productive			
Dry			
			1

(1) Gross interest reflects the total wells we participated in, regardless of our ownership interest.

Table of Contents

Customers

Revenue from customers exceeding 10% of our total revenue for 2010 and 2009 was as follows:

	Natural Gas and Oil Sales	Pipeline Operations	Customer Total	% of Total Revenue
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%
Year Ended December 31, 2009:				
Gryphon Exploration Co.	$	$ 379,828	$ 379,828	20%
W&T Offshore	$	$ 332,396	$ 332,396	18%
Helis Oil & Gas	$	$ 216,047	$ 216,047	12%
Maritech Resources	$	$ 191,512	$ 191,512	10%

Markets & Competition

The price and marketability of oil and natural gas depend on a number of factors that are beyond our control. These include, among other things:

- the level of domestic and foreign production;
- actions taken by foreign oil and gas producing nations;
- the availability of pipelines with adequate capacity;
- the availability of vessels for direct shipment;
- lightering, transshipment and other means of transportation;
- the availability and marketing of other competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and refined products; and
- the extent of governmental regulation and taxation (under both present and future legislation) of the production, importation, refining, transportation, pricing, use and allocation of oil, gas, refined products and alternative fuels.

In view of the many uncertainties that affect the supply and demand for crude oil, condensate, natural gas and refined petroleum products, it is impossible to accurately predict the price and marketability of our oil and natural gas production or the rates charged for our transportation and storage services. Currently, our oil production is sold at market prices at the time of lifting from our barge loading terminal, and our natural gas production is sold at market prices at the time of transmission to a major intrastate pipeline.

Vigorous competition occurs among energy providers across all energy sources. As an independent oil and gas company, in our midstream operations we face competition between producers, transporters, and distributors of oil and gas, as well as from other pipelines in the markets that we serve. The principal elements of competition among midstream companies are rates, service terms, market access, flexibility and service reliability. In the upstream sector, we compete for the acquisition of oil and natural gas properties with numerous entities, including major oil companies, independent oil and natural gas concerns and individual producers and operators, primarily on the basis of the price to be paid for such properties. Many of our competitors are large, well-established companies that have financial and other resources that are substantially greater than our own, which give them an advantage in evaluating and acquiring properties and prospects. Our future ability to engage new producers/shippers, acquire additional oil and natural gas properties and increase our reserves will depend on our ability to attract new and retain existing producers/shippers, evaluate and select suitable properties and consummate transactions in a highly

Table of Contents

competitive environment. In addition to these factors, we must maintain experienced personnel to manage and operate our assets.

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. The transportation and resale of 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 recently issued a Notice of Inquiry that could expand the reach of its regulation to aspects of intrastate pipelines. 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). FERC has stated that non-jurisdictional gathering lines, as well as interstate pipelines, are fully subject to the open access and nondiscrimination requirements of OCSLA s Section 5, which generally authorizes FERC to insure that gas pipelines on the Outer Continental Shelf (OCS) will transport for non-owner shippers in a nondiscriminatory manner and will be operated in accordance with certain pro-competitive principles. Since all of our offshore pipelines fall within the exemption for feeder facilities and already operate on the basis required under OCSLA, we do not anticipate significant changes directly resulting from requirements concerning nondiscriminatory open access transportation.

Table of Contents

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 has been subject to a variety of regulations promulgated by FERC and imposed on all oil pipelines pursuant to federal law. Recently, however, oil pipelines have been granted permanent exemptions from certain FERC filing requirements because of rulings that oil pipeline transportation tariff movements of crude petroleum occurring solely on or across the OCS, or across the OCS to onshore points where transportation ends, are not subject to FERC jurisdiction under the OCSLA or the Interstate Commerce Act. In 2010, we filed our effective tariffs with FERC in electronic format in compliance with FERC s Order No. 714 on Electronic Tariff Filings. The filing established a baseline tariff for FERC s tariff database. Our currently effective tariffs are available on our website.

Safety and Operational Regulations. Our operations are generally subject to safety and operational regulations administered primarily by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), the Department of Transportation, the Coast Guard, FERC and/or various state agencies. 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 BOEMRE. Such leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed BOEMRE regulations and orders pursuant to the OCSLA that are subject to interpretation and change by BOEMRE. For offshore operations, lessees must obtain BOEMRE 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 Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency (the EPA), lessees must obtain a permit from BOEMRE prior to the commencement of drilling. BOEMRE 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, BOEMRE 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 BOEMRE. Under some circumstances, BOEMRE 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, BOEMRE may also require any of our operations on federal leases to be suspended or terminated in the affected area. Furthermore, BOEMRE 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, processing and storage 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 a 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.

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

We have five (5) full-time employees and regularly use the services of two (2) consultants. Our employees, along with the expertise provided by our engineering and geology consultants, 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.

Executive Officers of the Registrant

Our executive officers as of March 31, 2011 are listed below:

Name	Office	Officer Since	Age
Ivar Siem	Chairman of the Board, Chief Executive Officer, President, Assistant Treasurer and Secretary	1989	64
T. Scott Howard	Treasurer and Assistant Secretary	2008	39

Ivar Siem has served as Chairman of the Board of Directors of Blue Dolphin since 1989. He was appointed as Chief Executive Officer in 2004 and as President, Assistant Treasurer and Secretary in 2010. Since 2000, he has also served as Chairman of the Board of Directors and Chief Executive Officer of Drillmar Energy Inc., a subsidiary of which filed for Chapter 11 bankruptcy reorganization in November 2009. From 1995 to 2000, he served as Chairman and director and interim President of DI Industries, which later became Grey Wolf, Inc. From 1996 to 1997, Mr. Siem also served as Chief Executive Officer of Seateam Technology ASA. From 1981 to 1995, Mr. Siem was an international consultant to companies in the energy, technology and finance industries. From 1974 to 1981, Mr. Siem held a variety of progressively responsible management positions within the Fred. Olsen group of companies, including President of Dolphin International, Inc. until it was sold in 1981. Mr. Siem began his career as a petroleum engineer for Amoco Corporation. He currently serves or has previously served on the Boards of Directors of several public and privately-held companies, including Avenir ASA, The Classical Theatre, Frupor SA, TI A/S, Siem Industries, Inc. and two of its affiliates. Mr. Siem holds a Bachelor of Science in Mechanical Engineering from the University of California, Berkeley, and has completed an executive MBA program at Amos Tuck School of Business, Dartmouth University.

T. Scott Howard was appointed as Treasurer of Blue Dolphin in 2009 and Assistant Secretary of Blue Dolphin in April 2008. He joined Blue Dolphin as Accounting Manager in 2006. From 1996 to 2006 he held a variety of management level positions: Audit Manager with DRDA, P.C., an independent public accounting firm in Houston, Texas from 2002 to 2006, Trust Officer with Frost National Bank in Houston, Texas from 2000 to 2002 and Controller for Hall s Insurance Agency, Inc. in Dickinson, Texas from 1996 to 2000. He began his career as a Staff Accountant for Griffin, Iles, Masel & Duval, LLP, a public accounting firm, where he was employed from 1994 to 1996. Mr. Howard, who is a Certified Public Accountant in Texas, received his Bachelor of Business Administration in Accounting from St. Edward s University.

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 Securities and Exchange Commission (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.

Information about each of our directors, as well as each of our 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. Liquid hydrocarbons associated with the production of a primarily gas reserve.

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.
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 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 costs of production.

Table of Contents

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.

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.

Risks Related to our Business

Based on our historical financials, there is uncertainty as to our ability to continue as a going concern.

As described in the report of our independent registered public accounting firm and in Note (1), Organization and Significant Accounting Policies, to the Notes to Consolidated Financial Statements included in this report, there is substantial doubt about our ability to continue as a going concern. We incurred a net loss of $1,022,895 for the year ended December 31, 2010. As of December 31, 2010, we had an accumulated deficit of $31,130,546. We anticipate that we will continue to incur substantial operating losses unless we are able to achieve and sustain profitability.

Our limited revenue and cash flow deficiencies raise substantial doubt as to our ability to continue as a going concern. Existing and anticipated working capital needs, lower than anticipated revenue, increased expenses and/or the inability to recover damages awarded under a partial summary judgment related to a defaulted loan could all affect our ability to continue as a going concern.

The continuation of our business is dependent upon obtaining additional financing. We will seek to raise additional working capital through private placements, sale of existing assets, public offerings, bank financing and/or advances from related parties or shareholder loans, as well as to continue evaluating potential merger and/or acquisition opportunities. There are no assurances that we will be able to raise additional capital through private placement, public offerings and/or bank financing, and this report may make it more difficult to raise such capital. Furthermore, the issuance of additional equity securities could result in a significant dilution in the equity interests of current or future stockholders. Obtaining commercial loans, assuming those loans would be available, will increase liabilities and future cash commitments. We do not currently have any arrangements in place to raise additional capital.

If the $1.7 million award under a partial summary judgment in favor of Blue Dolphin and against LEH and LLRII is not recovered, we could deplete our cash reserves by the end of the third quarter of 2011.

In the second quarter of 2010, we began foreclosure proceedings on the Collateral and Guaranty securing the Loan. The Collateral went up for auction under a Writ of Seizure and Sale issued by the 31st Judicial District Court, Parish of Jefferson Davis, State of Louisiana on July 28, 2010. There were no bidders on the property owned by LLRII. As a credit bid against the Loan, we bid the minimum amount of $134,000 for the property owned by LEN, which consisted primarily of an inactive salt water disposal well. As there were no third-party bidders on the property owned by LEN, we acquired the property at its fair market value of $201,000.

On May 26, 2010, we filed a petition in the Court alleging breach of contract and asserting our right to the unpaid principal balance and all accrued interest due and payable under the Loan. By order dated February 7, 2011, the Court granted a partial summary judgment on liability under the promissory note and Guaranty in favor of Blue Dolphin and against LEH and LLRII. On March 28, 2010, our motion for entry of the partial summary judgment was heard before the Court. The Court entered the partial summary judgment in the amount of $1.7 million in favor of Blue Dolphin and against LEH and LLRII on the promissory note and Guaranty. The only claim that remains pending is the counter-claim alleging breach of contract under the confidentiality agreement. Our cash flow projections suggest that, should the damages awarded under the partial summary judgment not be recovered, we could deplete our cash reserves by the end of the third quarter of 2011.

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

In the past four 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 through the third quarter of 2011. If we are unable to 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.

We are primarily dependent on revenue from our pipeline systems and our working interests in four oil and gas producing properties.

For the year ended December 31, 2010, approximately 69% of our revenue was derived from our pipeline operations. We expect that future revenue will continue to be primarily dependent on the usage level on our pipeline systems. Various factors can influence the usage level, including the success of drilling programs in the areas near our pipelines and our ability to attract new producer/shippers. There are various pipelines in and around our pipeline systems that we vigorously compete with for new producer/shippers. There can be no assurance that we will be successful in attracting new producer/shippers to our pipeline systems.

The rate of production from oil and gas properties generally declines as reserves are depleted. Most of our working interests are held in properties located in the U.S. Gulf of Mexico where the rate of production generally declines more rapidly than in many other producing areas of the world. As the production level from these properties continues to decline, our revenue from oil and gas sales will decrease. Revenue from oil and gas sales accounted for approximately 31% and 6% of our total revenue in 2010 and 2009, respectively. Unless we are able to offset declining production revenue with revenue from interests in new oil and gas properties, increased throughput from new or existing shippers/producers or acquire other revenue generating assets at an acceptable cost, our revenue and cash flow from operations will continue to decrease and our financial condition will be materially adversely affected.

A significant decrease in exploration and production activity within the areas where our pipelines are located would adversely affect our revenue and cash flow.

Our current business model is largely dependent upon the success of exploration and production activities along our pipeline corridors, which directly impacts our throughput volume. Current throughput on our pipelines is significantly below capacity. Failure to connect new wells to our pipelines, as well as declines in production from existing wells, will result in the amount of throughput being further reduced over time.

We have no control over the many factors that affect production activity, including prevailing and projected commodity prices, oil and gas demand, reserve levels, geological considerations, governmental regulation and the availability and cost of capital. Any decrease in our pipeline throughput will negatively impact our revenue and operating income.

The global financial crisis may have an impact on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital, which could have an adverse impact on our financial condition. Additionally, the current economic situation could lead to reduced demand for oil and natural gas, or lower prices for oil and natural gas, or both, which could have a negative impact on our revenue.

If our Common Stock is delisted from trading on the NASDAQ, the market price of our Common Stock could be adversely affected.

Our Common Stock is currently listed on the NASDAQ Capital Market under the symbol BDCO. NASDAQ Marketplace Rules require issuers to maintain a minimum of $2.5 million in stockholders equity for continued listing. On May 20, 2010, we were notified by NASDAQ that our stockholders equity had fallen below the minimum listing requirement. On May 27, 2010, we submitted a compliance plan to the Panel to cure the stockholders equity deficiency. The compliance plan provided a pro forma calculation of the impact of our working interest in the North Sumatra Basin-Langsa Field, as well as outlined our efforts to collect on the outstanding loan receivable. As permitted under NASDAQ Listing Rules, on June 23, 2010 the Panel granted us an extension for continued listing until compliance with the stockholders equity requirement was fully demonstrated. On November 24, 2010, we received confirmation from NASDAQ that we had cured our stockholders equity deficiency. The Panel will monitor our continued compliance with the stockholders equity rule for a period of one year. In the event we fall out of compliance during the monitoring period, the Panel may, at its discretion, delist our Common Stock.

There can be no assurance that we will be successful in maintaining the listing of our Common Stock on NASDAQ. A delisting of our Common Stock from NASDAQ could adversely affect the liquidity of our Common Stock and its market price. If NASDAQ delists our Common Stock, and our Common Stock is not eligible for quotation on another market or exchange, trading of our Common Stock could be conducted in the over-the-counter market or the pink sheets. In such event, it could become more difficult to dispose of or obtain accurate price quotations for our Common Stock, and there would likely be a reduction in coverage by security analysts and the news media, all of which could cause the price of our Common Stock to decline further. If an active trading market for our Common Stock is not sustained, it will be difficult for our shareholders to sell their shares without further depressing the market price of our Common Stock. Delisting of our Common Stock could also make it more difficult to obtain financing or consummate deals for the continuation of our operations.

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

The majority of our assets are located in the U.S. Gulf of Mexico and Texas Gulf Coast region. As a result, we are at a greater risk of being impacted by local 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.

Table of Contents

A substantial and extended decline in the prices of oil and gas would have a material adverse effect on our operations.
As a significant portion of our reserves are natural gas, we are impacted more by changes in natural gas prices. The tightening of natural gas supplies and demand fundamentals has resulted in extremely volatile natural gas prices, and this volatility in natural gas prices is expected to continue. 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:

- U.S. weather conditions;
- the U.S. economy;
- Organization of Petroleum Exporting Countries actions;
- governmental regulation;
- political stability in the Middle East, South America and elsewhere;
- the foreign supply of oil and natural gas;
- the price of foreign imports;
- the 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 reserves held by third party companies around our pipeline systems;
- increasing our dependence on external sources of capital to meet our cash needs; and
- impairing our ability to obtain needed capital.

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 gas 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 deals and acquiring new oil and gas properties.

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.

Table of Contents

The proved reserve information set forth in this report is based on estimates we prepared. Estimates prepared by others might differ materially from our estimates. Actual quantities of recoverable oil and gas reserves, future production, oil and gas prices, taxes, development expenditures, abandonment costs and operating expenses most likely will vary from our estimates. Any significant variance could materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development and prevailing oil and gas prices. Our reserves also may be susceptible to drainage by operators on adjacent properties.

The present value of future net cash flows will most likely not equate to the current market value of our estimated proved oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves 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, 2010. Actual future prices and costs may be materially different from the prices and costs we used.

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

Currently, third parties operate or control the development of the oil and gas properties in which we have an interest. As a result, we depend on these third party operators 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.

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.

We have pursued and 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 and oil and gas assets that are complementary to our existing business operations. 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, including those specific to the marine environment, 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:

- 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;
- explosions;
- fires;
- pollution; 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.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and results of operations.

We maintain several types of insurance to cover our operations, including maritime employer s liability and comprehensive general liability. Amounts exceeding base coverages are provided by primary and excess umbrella liability policies. We also maintain operator s extra expense coverage, which covers the control of drilled or producing wells and re-drilling expenses, as well as pollution coverage for out of control wells.

We may not be able to maintain adequate insurance in the future at rates we consider reasonable, or losses may exceed the maximum coverage amounts under our insurance policies. We do not maintain property insurance coverage on our pipelines. If a significant event occurs that is not fully insured or indemnified against, such event could materially and adversely affect our financial condition and results of operations.

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

We currently have five (5) full-time employees and regularly use the services of two (2) consultants. Success within our existing two business segments pipeline operations and activities and oil and gas exploration and production activities depends largely upon the efforts of certain of our executive officers, one of which has been employed by us since the early stages of our business, and continued access to the two (2) consultants, both of whom are also former employees with a long history with Blue Dolphin. The loss of services of any one of these individuals could seriously harm our business opportunities and prospects. Given our small size, our success also depends on the retention of qualified personnel in key areas. 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.

Table of Contents

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;
- 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information appearing in Item 1. Business describing our oil and gas properties, pipelines and other assets is incorporated herein by reference.

We lease our executive offices in Houston, Texas under an operating lease expiring April 30, 2017. Our average annual lease payment under this lease is approximately $108,000.

Table of Contents

ITEM 3. LEGAL PROCEEDINGS

In the second quarter of 2010, we began foreclosure proceedings on the Collateral and Guaranty securing the Loan:

Blue Dolphin v. LLRII (State of Louisiana). The Collateral went up for auction under a Writ of Seizure and Sale issued by the 31st Judicial District Court, Parish of Jefferson Davis, State of Louisiana on July 28, 2010. There were no bidders on the property owned by LLRII. As a credit bid against the Loan, we bid the minimum amount of $134,000 for the property owned by LEN, which consisted primarily of an inactive salt water disposal well. As there were no third-party bidders on the property owned by LEN, we acquired the property at the fair market value of $201,000.

Blue Dolphin v. LEH (State of Texas). On May 26, 2010, we filed a petition in the Court alleging breach of contract and asserting our right to the unpaid principal balance and all accrued interest due and payable under the Loan. Although LEH filed a counter-claim alleging usurious interest based on a $500,000 consulting agreement made between the parties, in September 2010 we exercised our right to cure the alleged usury without having to admit guilt based on a statutory provision. In so doing, the Borrower was credited $500,000 against the outstanding principal balance, and the matter proceeded without undue delay. In response, LEH filed an amended counter-claim further alleging breach of contract under the confidentiality agreement between the parties. By order dated February 7, 2011, the Court granted a partial summary judgment on liability under the promissory note and Guaranty in favor of Blue Dolphin and against LEH and LLRII. The Court, however, deferred a ruling on the damages and attorney s fees to be awarded. Although the parties reached an agreement regarding the amount of attorneys fees to be awarded, and the defendants do not dispute the calculation of damages sought by Blue Dolphin, the defendants continue to contest Blue Dolphin s entitlement to summary judgment. On February 25, 2011, we filed a motion for entry of the partial summary judgment. On March 28, 2010, our motion for entry of the partial summary judgment was heard before the Court. The Court entered the partial summary judgment in the amount of $1.7 million in favor of Blue Dolphin and against LEH and LLRII on the promissory note and Guaranty. The only claim that remains pending is the counter-claim alleging breach of contract under the confidentiality agreement.

ITEM 4. (REMOVED AND RESERVED)

Remainder of Page Intentionally Left Blank

Table of Contents

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 NASDAQ Capital Market under the ticker symbol BDCO. As of March 31, 2011, we had 292 record holders of our Common Stock. Based on the record date for our 2010 annual meeting of stockholders, which was held on May 27, 2010, we had approximately 2,000 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 NASDAQ. NASDAQ quotations reflect inter-dealer prices, without adjustment for retail mark-ups, markdowns or commissions and may not represent actual transactions.

Quarter Ended	High(1)	Low(1)
2010		
December 31	$ 2.88	$ 1.70
September 30	$ 3.64	$ 0.99
June 30	$ 4.89	$ 1.33
March 31	$ 4.86	$ 2.24
2009		
December 31	$ 4.34	$ 2.03
September 30	$ 4.06	$ 2.73
June 30	$ 5.53	$ 2.52
March 31	$ 3.15	$ 1.82

(1) Adjusted to reflect our reverse stock split, which occurred in the quarter ended September 30, 2010.

We were notified by NASDAQ on March 16, 2010, that our Common Stock was subject to delisting for failure to comply with the minimum bid price requirement, and we were also notified by NASDAQ on May 20, 2010, that our Common Stock failed to meet the stockholders equity requirement. Both deficiencies were cured during 2010. See Recent Developments in Part I, Item 1. Business for additional information related to our efforts to achieve compliance with NASDAQ s listing requirements.

At the recommendation of our Board, our stockholders approved a 1 for 7 (1:7) reverse stock split of our Common Stock on June 9, 2010. The effective date for the reverse stock split was July 16, 2010. See Recent Developments in Part I, Item 1. Business for additional information related to the reverse stock split.

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.

Equity Compensation Plan Information

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2010, 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	30,390	$ 13.29	1,107,564
Equity compensation plans not approved by security holders		$ 0.00	
Total	30,390	$ 13.29	1,107,564

Remainder of Page Intentionally Left Blank

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
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
Impairment of oil and gas properties					
Recovery of allowance for doubtful loan receivable			(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)
2009					
Revenue from operations:					
Pipeline operations	$ 514,759	$ 548,636	$ 442,249	$ 361,327	$ 1,866,971
Oil and gas sales	21,946	44,075	42,269	17,687	125,977
Total revenue from operations	536,705	592,711	484,518	379,014	1,992,948
Cost of operations:					
Pipeline operating expenses	466,260	491,461	309,695	247,946	1,515,362
Lease operating expenses	48,031	674	29,731	16,705	95,141

Depletion, depreciation and amortization	128,913	134,227	133,362	120,840	517,342
Impairment of oil and gas properties	203,110				203,110
Allowance for doubtful note receivable, net of consulting agreement				1,500,000	1,500,000
General and administrative expenses	602,194	650,754	372,159	364,925	1,990,032
Stock based compensation	62,644	40,320	62,562	39,320	204,846
Accretion expense	27,918	27,919	27,586	27,420	110,843
Total cost of operations	1,539,070	1,345,355	935,095	2,317,156	6,136,676
Other income (expense), including income tax expense	2,356	2,395	129,191	(127,106)	6,836
Net loss	$ (1,000,009)	$ (750,249)	$ (321,386)	$ (2,065,248)	$ (4,136,892)
Loss per share:					
Basic and diluted	$ (0.60)	$ (0.45)	$ (0.19)	$ (1.22)	$ (2.46)

Table of Contents

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 Notes to Consolidated Financial Statements.

Executive Summary

We are engaged in two lines of business: (i) pipeline transportation services to producer/shippers, and (ii) oil and gas exploration and production. Our pipeline assets are located offshore and onshore 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 in offshore Indonesia. Our goal is to create greater long-term value for our stockholders by increasing reserves and improving operational income while pursuing a balanced growth strategy employing varying elements of exploration, development and acquisition activities.

Pipeline Operations.

- *BDPS* The BDPS is currently transporting an aggregate of approximately 9 MMcf of gas per day from 7 shippers, which represents 5% of throughput capacity.
- *GA 350 Pipeline* The GA 350 Pipeline is currently transporting an aggregate of approximately 14 MMcf of gas per day from 5 shippers, which represents 22% of throughput capacity.

Exploration and Production.

- *Galveston Area Block 321* The A-4 Well is commingled in the 5,400 and 5,300 sands. Once this commingled completion depletes, there are two upper zones up the hole with booked reserves. The A-4 Well is currently producing approximately 1.2 MMcf of gas per day and 110 barrels of oil per day.
- *High Island Block 115* The B-1 ST2 Well resumed production in July 2010 after being shut-in since August 2009 due to production handling problems on our downstream production handling platform, High Island Block 71. The B-1 ST2 Well is currently producing approximately 4.2 MMcf of gas per day.
- *High Island Block 37* Production from the A-2 Well was restarted in February 2009, after being shut-in since September 2008 following Hurricane Ike. The A-2 Well is currently producing approximately 0.8 MMcf of gas per day.
- *North Sumatra Basin-Langsa Field* The H-4 Well is currently producing approximately 430 barrels of oil per day.

Our pipeline assets remain significantly underutilized. Production declines, temporary stoppages or cessations of production from wells tied into our pipelines or from wells in which we have a working and overriding royalty interest, as noted herein, could have a material adverse effect on our cash flows and liquidity if the resulting revenue declines are not offset by revenue from other sources. Due to our small size, geographically concentrated asset base and limited capital resources, any negative event has the potential to have a material adverse impact on our financial condition. We are continuing our efforts to increase the utilization of our existing assets and acquire additional assets that will diversify the risks to our cash flows and be accretive to earnings.

Table of Contents

Results of Operations

For the year ended December 31, 2010 (the current period), we reported a net loss of $1,022,895, compared to a net loss of $4,136,892 for the year ended December 31, 2009 (the previous period). For the three months ended December 31, 2010 (the current quarter), we reported a net loss of $58,122 compared to a net loss of $2,065,248 for the three months ended December 31, 2009 (the previous quarter).

2010 Compared to 2009

Revenue from Pipeline Operations. Revenue from pipeline operations increased by $11,915, or 0.6%, in the current period to $1,878,886. Revenue in the current period from the BDPS totaled approximately $1,538,000 compared to approximately $1,498,000 in the previous period primarily due to increased commodity prices on the oil sold from our Freeport facility. Daily gas volumes transported through the BDPS averaged approximately 14 MMcf of gas per day in the current period compared to approximately 16 MMcf of gas per day in the previous period. Revenue on the GA 350 Pipeline decreased by approximately $28,000 to approximately $341,000 in the current period primarily due to natural production declines. Average daily gas volumes for GA 350 transported decreased to approximately 17 MMcf of gas per day in the current period from approximately 19 MMcf of gas per day in the previous period.

Revenue from Oil and Gas Sales. Revenue from oil and gas sales increased by $736,708, or 584%, to $862,685 in the current period primarily due to the addition of production from the North Sumatra Basin-Langsa Field, as well as the B-1 ST-2 Well in High Island Block 115 coming back online after being off production for nearly a year due to production problems on the downstream production handling platform.

Our average realized gas price per Mcf in the current period was $3.85 compared to $3.23 in the previous period. The sales mix by product was 86% oil and 14% gas. Our average realized price per barrel of oil was $88.14 in the current period compared to $69.60 in the previous period. Revenue breakdown for the current period by field was approximately $48,200 for Galveston Area Block 321, $48,900 for High Island Block 115, $45,300 for High Island Block 37 and $720,300 for the North Sumatra Basin-Langsa Field.

Pipeline Operating Expenses. Pipeline operating expenses decreased by $416,765, or 28%, to $1,098,597 in the current period. The decrease was primarily due to decreases in insurance expense, storage tank repairs, leak repairs, crane repairs, and other operating expenses. The decreases were partially offset by an increase in consulting expenses.

Lease Operating Expenses. Lease operating expenses increased $578,627, or 608%, in the current period to $673,768 primarily due to the addition of expenses from the North Sumatra Basin-Langsa Field, as well as the B-1 ST-2 Well in High Island Block 115 coming back online after being off production for nearly a year due to production problems on our downstream production handling platform. Lease operating costs associated with North Sumatra Basin-Langsa Field totaled approximately $601,000 for the current period.

Depletion, Depreciation and Amortization. Depletion, depreciation and amortization increased by $101,987, or 20%, in the current period to $619,329 primarily due to the acquisition of the North Sumatra Basin-Langsa Field, with associated depletion of approximately $79,000.

Impairment of Oil and Gas Properties. We use 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 calculated using domestic prices of $79.61 per barrel of oil and $4.33 per MMbtu of gas and an international price of $80.35 per barrel of oil. As our costs fell below our ceiling limitation at March 31, 2010, June 30, 2010, September 30, 2010 and December 31, 2010, we did not have an impairment of oil and gas properties in the current period. Our ceiling for the previous period was calculated using prices of $47.19 per barrel of oil and $3.65 per MMbtu of gas. At March 31, 2009, our costs exceeded our ceiling limitation, resulting in a write-down of our oil and gas properties of $203,110.

General and Administrative Expenses and Stock Based Compensation. General and administrative expenses and stock based compensation expenses decreased by $713,315, or 33%, in the current period to $1,481,563 primarily due to decreases in officer salaries, employee related expenses, consulting fees, and office expense. The decreases were partially offset by increases in audit expense, legal fees, insurance expense and stock maintenance fees.

Recovery of Allowance for Doubtful Loan Receivable. Recovery for allowance for doubtful loan receivable increased by $201,000 in the current period primarily due to the addition of a disposal well at its fair market value of $201,000 as recovery of a previously recorded bad debt expense on the outstanding loan receivable of $2.0 million, net of credited and recovered amounts.

Three Months Ended December 31, 2010 Compared to Three Months Ended December 31, 2009

Revenue from Pipeline Operations. Revenue from pipeline operations increased by $123,711, or 34%, in the current quarter to $485,038 primarily due to an increase in oil volumes transported. Revenue in the current quarter from the BDPS increased to approximately $397,500 compared to approximately $280,000 in the previous quarter. Daily gas volumes transported on the BDPS averaged 12 MMcf of gas per day in the current quarter compared to 13 MMcf of gas per day in the previous quarter. Revenue on the GA 350 Pipeline decreased to approximately $87,500 compared to approximately $81,000 in the previous quarter due to an increase in average daily gas volumes transported of 17 MMcf of gas per day in the current quarter from 16 MMcf of gas per day in the previous quarter.

Revenue from Oil and Gas Sales. Revenue from oil and gas sales increased by $566,837 to $584,524 in the current quarter primarily as a result of the addition of production from the North Sumatra Basin-Langsa Field and the B-1 ST-2 Well in High Island Block 115, the latter of which came back online after being off production for nearly a year due to production problems on the downstream production handling platform.

Pipeline Operating Expenses. Pipeline operating expenses in the current quarter decreased by $5,191, or 2%, to $242,755.

Lease Operating Expenses. Lease operating expenses increased in the current quarter by $407,032 to $423,737 due to the addition of expenses from the North Sumatra Basin-Langsa Field, as well as the B-1 ST-2 Well in High Island Block 115 coming back online after being off production for nearly a year due to production problems on our downstream production handling platform.

Depletion, Depreciation and Amortization. Depletion, depreciation and amortization increased by $34,683, or 29%, in the current period to $155,523 primarily due to the acquisition of the North Sumatra Basin-Langsa Field.

General and Administrative Expenses and Stock Based Compensation. General and administrative expenses and stock based compensation expenses decreased by $120,979, or 30%, to $283,266 in the current quarter primarily due to decreases in officer salaries and consulting expense.

Table of Contents

Liquidity and Capital Resources

Sources and Uses of Cash. Our primary source of cash is cash flow from operations and cash on hand. During 2010, we had negative cash flow from operations of approximately $124,953, mainly due to low utilization of our pipeline systems.

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, 2010, our current available cash was $625,854.

	For Year Ended December 31, 2010	2009
Cash flow from operations		
Loss from operations	$ (350,812)	$ (1,520,751)
Change in current assets and liabilities	226,219	388,143
Total cash flow from operations	(124,593)	(1,132,608)
Cash outflows		
Capital expenditures and advance of loan receivable	(58,719)	(1,515,643)
Payments on financing activities	(207,317)	(200,142)
Total cash outflows	(266,036)	(1,715,785)
Total change in cash flows	$ (390,629)	$ (2,848,393)

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

Going Concern. As described in the report of our independent registered public accounting firm and in Note (1), Organization and Significant Accounting Policies, to the Notes to Consolidated Financial Statements included in this report, there is substantial doubt about our ability to continue as a going concern. We incurred a net loss of $1,022,895 for the year ended December 31, 2010. As of December 31, 2010, we had an accumulated deficit of $31,130,546. We anticipate that we will continue to incur substantial operating losses unless we are able to achieve and sustain profitability.

Our limited revenue and cash flow deficiencies raise substantial doubt as to our ability to continue as a going concern. Existing and anticipated working capital needs, lower than anticipated revenue, increased expenses and/or the inability to recover damages awarded under a partial summary judgment related to a defaulted loan could all affect our ability to continue as a going concern.

The continuation of our business is dependent upon obtaining additional financing. We will seek to raise additional working capital through private placements, sale of existing assets, public offerings, bank financing and/or advances from related parties or shareholder loans, as well as to continue evaluating potential merger and/or acquisition opportunities. There are no assurances that we will be able to raise additional capital through private placement, public offerings and/or bank financing, and this report may make it more difficult to raise such capital. Furthermore, the issuance of additional equity securities could result in a significant dilution in the equity interests of current or future stockholders. Obtaining commercial loans, assuming those loans would be available, will increase liabilities and future cash commitments. We do not currently have any arrangements in place to raise additional capital.

Table of Contents

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 pipeline assets, as well as the evaluation and collection of the note receivable, as of December 31, 2010 and the accounting for future asset retirement costs.

Accounting for the Impairment or Disposal of Long-Lived Assets. In accordance with Financial Accounting Standards Board (FASB) guidance 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, 2010. Accordingly, we developed future cash flows as of December 31, 2010 expected to be generated 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, 2010.

Asset Retirement Obligations. The accounting for future abandonment costs changed in August 2001, with the adoption of FASB s 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. We adopted FASB s accounting for uncertainty in income taxes effective January 1, 2007. The 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.

The provisions of the guidance have been applied to all of our material tax positions taken from January 1, 2007 through the fiscal year ended December 31, 2010. 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. On January 1, 2008, we adopted FASB s 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. In February 2008, FASB issued a staff position that deferred the effective date of the guidance for one year for nonfinancial assets and liabilities recorded at fair value on a non-recurring basis. The effect of adoption of the guidance for financial assets and liabilities recognized at fair value on a recurring basis did not have a material impact on our financial position and results of operations.

Fair Value Option for Financial Assets and Financial Liabilities. On January 1, 2008, we adopted FASB s guidance on the fair value option for financial assets and financial liabilities. The guidance permits companies to choose an irrevocable election to measure certain financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings at each subsequent reporting date. We did not elect the fair value option under the guidance for any of our financial assets or liabilities upon adoption.

Recently Adopted Accounting Pronouncements

Generally Accepted Accounting Principles. In June 2009, the FASB issued guidance that established the Accounting Standards Codification as the sole source of authoritative GAAP. We updated references to GAAP in our financial statements pursuant to the provisions of FASB s guidance. The adoption of FASB s guidance did not impact our financial position or results of operations.

Recently Issued Accounting Pronouncements and Accounting Developments

Fair Value Measurements. In January 2010, the FASB issued guidance that requires reporting entities to make new disclosures about recurring or nonrecurring fair-value measurements including significant transfers into and out of Level 1 and Level 2 fair value measurements and information on purchases, sales, issuances and settlements on a gross basis in the reconciliation of Level 3 fair value measurements. The guidance is effective for annual reporting periods beginning after December 15, 2009, except for Level 3 reconciliation disclosures that are deferred to annual periods beginning after December 15, 2010. The adoption of this guidance did not have a material impact on our consolidated financial statements and we do not expect the deferral provisions to have a material impact on our consolidated financial statements.

Variable Interest Entities. In December 2009, the FASB issued revised authoritative guidance associated with the consolidation of variable interest entities. This revised guidance replaces the current quantitative-based assessment for determining which enterprise has a controlling financial interest in a variable interest entity with an approach that is now primarily qualitative. This qualitative approach focuses on identifying the enterprise that has: (i) the power to direct the activities of the variable interest entity that can most significantly impact the entity s economic performance and (ii) the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the variable interest entity. This revised guidance also requires an ongoing assessment of whether an enterprise is the primary beneficiary of a variable interest entity rather than a reassessment only upon the occurrence of specific events. The revised guidance is effective for financial statements issued for fiscal years beginning after November 15, 2009. The implementation of this guidance did not have any impact on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

None.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements:

Remainder of Page Intentionally Left Blank

Table of Contents

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, 2010 and 2009, 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, 2010. 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 of the 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 Blue Dolphin Energy Company and Subsidiaries as of December 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note (1), Organization and Significant Accounting Policies , to the notes to consolidated financial statements, the Company has suffered recurring losses and negative cash flows from operations that raise substantial doubt about its ability to continue as a going concern. Management s plans in regard to these matters are also described in Note (1), as referenced herein. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ UHY LLP
Houston, Texas
March 31, 2011

Table of Contents

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 625,854	$ 1,016,483
Accounts receivable, net of allowance for doubtful accounts	598,391	428,124
Loan receivable, net of allowance for loan receivable		
Prepaid expenses and other current assets	213,071	359,850
Total current assets	1,437,316	1,804,457
Property and equipment, at cost:		
Oil and gas properties (full-cost method)	2,222,535	1,086,733
Pipelines	4,659,686	4,659,686
Onshore separation and handling facilities	1,919,402	1,919,402
Land	860,275	860,275
Other property and equipment	503,813	302,813
	10,165,711	8,828,909
Less: Accumulated depletion, depreciation and amortization	5,630,730	5,011,401
Total property and equipment, net	4,534,981	3,817,508
Other assets	9,463	9,463
Total assets	$ 5,981,760	$ 5,631,428
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 543,327	$ 372,275
Note payable insurance	124,936	173,479
Asset retirement obligation current portion	192,470	
Accrued expenses and other liabilities	2,142	8,136
Other long-term liabilities current portion		25,996
Total current liabilities	862,875	579,886
Long-term liabilities:		
Asset retirement obligations, net of current portion	2,535,386	2,262,018
Other long-term liabilities, net of current portion		
Total long-term liabilities	2,535,386	2,262,018

Total liabilities	3,398,261	2,841,904
Commitments and contingencies		
Stockholders equity:		
Common stock ($0.01 par value, 100,000,000 shares authorized, 2,078,514 and 1,696,710 shares issued and outstanding at December 31, 2010 and 2009, respectively)	20,785	16,967
Additional paid-in capital	33,693,260	32,880,208
Accumulated deficit	(31,130,546)	(30,107,651)
Total stockholder s equity	2,583,499	2,789,524
Total liabilities and stockholders equity	$ 5,981,760	$ 5,631,428

See accompanying notes to consolidated financial statements.

39

Table of Contents

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Statements of Operations

	Years Ended December 31, 2010	2009
Revenue from operations:		
Pipeline operations	$ 1,878,886	$ 1,866,971
Oil and gas sales	862,685	125,977
Total revenue from operations	2,741,571	1,992,948
Cost of operations:		
Pipeline operating expenses	1,098,597	1,515,362
Lease operating expenses	673,768	95,141
Depletion, depreciation and amortizaton	619,329	517,342
Impairment of oil and gas properties		203,110
Allowance for doubtful note receivable		1,500,000
Recovery of allowance for doubtful loan receivable	(201,000)	
General and administrative expenses	1,427,803	1,990,032
Stock-based compensation	53,760	204,846
Accretion expense	119,994	110,843
Total cost of operations	3,792,251	6,136,676
Loss from operations	(1,050,680)	(4,143,728)
Other income (expense):		
Interest and other income	32,370	9,921
Total other income (expense)	32,370	9,921
Loss before income taxes	(1,018,310)	(4,133,807)
Income tax expense	(4,585)	(3,085)
Net loss	$ (1,022,895)	$ (4,136,892)
Loss per common share:		
Basic	$ (0.55)	$ (2.46)
Diluted	$ (0.55)	$ (2.46)
Weighted average number of common shares outstanding:		
Basic	1,864,354	1,683,678

Diluted	1,864,354	1,683,678

See accompanying notes to consolidated financial statements.

Table of Contents

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, 2008	1,670,178	$ 16,702	$ 32,595,627	$ (25,970,759)	$ 6,641,570
Common stock issued for services	26,532	265	79,735		80,000
Stock-based compensation			204,846		204,846
Net loss				(4,136,892)	(4,136,892)
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

See accompanying notes to consolidated financial statements.

Remainder of Page Intentionally Left Blank

Table of Contents

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Years Ended December 31, 2010	2009
OPERATING ACTIVITIES		
Net loss	$ (1,022,895)	$ (4,136,892)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depletion, depreciation and amortization	619,329	517,342
Recovery of previous allowance for doubtful loan receivable	(201,000)	
Impairment of oil and gas properties		203,110
Accretion expense	119,994	110,843
Stock-based compensation	53,760	204,846
Common stock issued for services	80,000	80,000
Allowance for doubtful note receivable, net of consulting agreement		1,500,000
Changes in operating assets and liabilities:		
Accounts receivable	(170,267)	14,591
Prepaid expenses and other current assets	302,949	450,013
Abandonment costs incurred	(45,525)	(32,015)
Accounts payable, accrued expenses and other liabilities	139,062	(44,446)
Net cash used in operating activities	(124,593)	(1,132,608)
INVESTING ACTIVITIES		
Advance of loan receivable		(1,500,000)
Exploration and development costs		(3,143)
Capital expenditures	(58,719)	(12,500)
Net cash used in investing activities	(58,719)	(1,515,643)
FINANCING ACTIVITIES		
Payments on notes payable	(204,713)	(200,142)
Retirement of fractional shares	(2,604)	
Net cash used in financing activities	(207,317)	(200,142)
Decrease in cash and cash equivalents	(390,629)	(2,848,393)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,016,483	3,864,876
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 625,854	$ 1,016,483
Non-cash investing and financing activities:		
Financing of insurance premiums	$ 156,170	$ 373,621
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	$	391,369	$

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements

(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 March 16, 2010, our Board of Directors (the Board) approved and authorized, subject to stockholder approval, implementation of 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 reverse stock split was approved by our stockholders on June 9, 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). 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.

Going Concern

Our consolidated financial statements, which have been prepared in accordance with GAAP, contemplate that we will continue as a going concern. As such, our consolidated financial statements do not contain any adjustments that might result if we were unable to continue as a going concern. We incurred a net loss of $1,022,895 for the year ended December 31, 2010. As of December 31, 2010, we had an accumulated deficit of $31,130,546. We anticipate that we will continue to incur substantial operating losses unless we are able to achieve and sustain profitability.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Our limited revenue and cash flow deficiencies raise substantial doubt as to our ability to continue as a going concern. Existing and anticipated working capital needs, lower than anticipated revenue, increased expenses and/or the inability to recover damages awarded under a partial summary judgment related to a defaulted loan could all affect our ability to continue as a going concern.

The continuation of our business is dependent upon obtaining additional financing. We will seek to raise additional working capital through private placements, sale of existing assets, public offerings, bank financing and/or advances from related parties or shareholder loans, as well as to continue evaluating potential merger and/or acquisition opportunities. There are no assurances that we will be able to raise additional capital through private placement, public offerings and/or bank financing, and this report may make it more difficult to raise such capital. Furthermore, the issuance of additional equity securities could result in a significant dilution in the equity interests of current or future stockholders. Obtaining commercial loans, assuming those loans would be available, will increase liabilities and future cash commitments. We do not currently have any arrangements in place to raise additional capital.

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.

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 domestic properties and one cost center for foreign 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 we prepare internally. 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, we recorded an impairment to our oil and gas properties of $203,110 in 2009. We recorded no such impairment in

Table of Contents

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

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 Financial Accounting Standards Board (FASB) standards 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.

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.

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.

Remainder of Page Intentionally Left Blank

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

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, 2010 and 2009 (amounts in thousands).

	Years Ended December 31, 2010	2009
Beginning asset retirement obligations	$ 2,262	$ 2,183
Liabilities incurred	392	
Liabilities settled	(46)	(32)
Accretion expense	120	111
Ending asset retirement obligations	$ 2,728	$ 2,262

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 vesting 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, 2010 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.

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, 2010 and 2009, we recorded an allowance for doubtful accounts of $0 and $0, respectively, related to accounts receivable.

Table of Contents

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

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 FASB s guidance on 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 years ended December 31, 2010 and 2009, because their assumed exercise and conversion would have an anti-dilutive effect on the computation of diluted loss per share.

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

	Year Ended December 31,	
Basic and Diluted	2010	2009
Net loss	$ (1,022,895)	$ (4,136,892)
Weighted average number of shares of common stock outstanding and potential dilutive shares of common stock	1,864,354	1,683,678
Per share amount	$ (0.55)	$ (2.46)

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

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, 2010 and 2009, no environmental violation was recorded on our consolidated balance sheets.

Recently Adopted Accounting Pronouncements

Generally Accepted Accounting Principles. In June 2009, the FASB issued guidance that established the Accounting Standards Codification as the sole source of authoritative GAAP. We updated references to GAAP in our consolidated financial statements pursuant to the provisions of FASB s guidance. The adoption of FASB s guidance did not impact our consolidated financial position or results of operations.

Recently Issued Accounting Pronouncements

Fair Value Measurements. In January 2010, the FASB issued guidance that requires reporting entities to make new disclosures about recurring or nonrecurring fair-value measurements including significant transfers into and out of Level 1 and Level 2 fair value measurements and information on purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair value measurements. The guidance is effective for annual reporting periods beginning after December 15, 2009, except for Level 3 reconciliation disclosures that are deferred to annual periods beginning after December 15, 2010. Adoption of this guidance did not have a material impact on our consolidated financial statements and we do not expect the deferral provisions to have a material impact on our consolidated financial statements.

Variable Interest Entities. In December 2009, the FASB issued revised authoritative guidance associated with the consolidation of variable interest entities. This revised guidance replaces the current quantitative-based assessment for determining which enterprise has a controlling financial interest in a variable interest entity with an approach that is now primarily qualitative. This qualitative approach focuses on identifying the enterprise that has: (i) the power to direct the activities of the variable interest entity that can most significantly impact the entity s economic performance and (ii) the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the variable interest entity. This revised guidance also requires an ongoing assessment of whether an enterprise is the primary beneficiary of a variable interest entity rather than a reassessment only upon the occurrence of specific events. The revised guidance is effective for financial statements issued for fiscal years beginning after November 15, 2009. The implementation of this guidance did not have any impact on our consolidated financial statements.

(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

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 or the Borrower) on July 31, 2009 and due on January 31, 2010. As of December 31, 2010, we continued to maintain an allowance for the uncollected balance of the Loan.

In the second quarter of 2010, we began foreclosure proceedings in Louisiana against the collateral, as well as legal proceedings in Texas against the guaranty, that secured the Loan. As a result of a foreclosure auction in Louisiana, we acquired a salt water disposal well in the third quarter of 2010. Based on the asset s appraised value, we recovered $201,000 of the allowance for doubtful loan receivable. Under the legal proceedings in Texas, we were granted a partial summary judgment on liability under the promissory note and guaranty in favor of Blue Dolphin. However, the court deferred a ruling on the damages and attorney s fees to be awarded. On March 28, 2010, our motion for entry of the partial summary judgment was heard before the court. The court entered the partial summary judgment in the amount of $1.7 million in favor of Blue Dolphin and against LEH and LLRII on the promissory note and guaranty. The only claim that remains pending is the counter-claim alleging breach of contract under the confidentiality agreement.

(4) Income Taxes

Income tax expense consisted of $4,585 and $3,085 and was related to state income tax for the years ended 2010 and 2009, 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, 2010 and 2009 are presented below:

	2010	2009
Deferred tax assets:		
Net operating loss and capital loss carryforwards	$ 7,236,636	$ 7,029,596
AMT credit carryforward	11,564	11,564
Basis differences in property and equipment	596,354	470,908
Total deferred tax assets	7,844,554	7,512,068
Less: valuation allowance	(7,844,554)	(7,512,068)
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, 2010 and 2009 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 years ended December 31, 2010 and 2009 was an increase of $332,486 and $1,304,427, respectively.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Our effective tax rate applicable to continuing operations in 2010 and 2009 is as follows:

	Years Ended December 31,	
	2010	2009
Expected tax rate	(34.00%)	(34.00%)
Change in valuation allowance recognized in earnings	34.42%	34.07%
	0.42%	0.07%

For federal tax purposes, we had net operating loss carry-forwards (NOLs) of approximately $21.3 million at December 31, 2010. These NOLs must be used prior to their expiration, which will occur between 2011 and 2030.

We adopted FASB s 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, 2010. 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.

In May 2006, the State of Texas enacted a new business tax that is imposed on gross revenue to replace its current 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 FASB guidance, we have properly determined the impact of the newly-enacted legislation in the determination of our reported state current and deferred income tax liability.

As part of the adoption 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, 2010 and 2009. Furthermore, none of our federal and state income tax returns are currently under examination by the Internal Revenue Service (IRS) or state authorities, but fiscal years 2006 and later remain subject to examination by the IRS and the 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 reserved for grants of incentive stock options (ISOs) and other stock-based awards under the 2000 Plan was increased to 1,200,000 shares. As of December 31, 2010, we had 1,107,564 shares of Common Stock available for future grants. Options granted under the 2000 Plan have

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

contractual terms ranging 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.

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 FASB 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, 2010 and 2009. Expected volatility 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. This weighting method was chosen to account for the significant changes in our financial condition beginning approximately four years ago. These changes include decreases in our working capital and pipeline throughput, as well as the reduction and ultimate elimination of our outstanding debt.

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 Securities and Exchange Commission (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 was used. No forfeiture rate was 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.

Remainder of Page Intentionally Left Blank

Table of Contents

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

At December 31, 2010, there were a total of 30,390 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:

	Year Ended December 31, 2010			
	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Options outstanding at December 31, 2008	79,360	$ 17.01		
Options granted		$ 0.00		
Options exercised		$ 0.00		
Options expired or cancelled	(18,714)	$ 14.91		
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 exercisable at December 31, 2010	30,390	$ 13.29	2.8	$

Remainder of Page Intentionally Left Blank

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, 2010:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$2.45 to $5.60	10,118	2.3	$ 3.06	10,118	$ 3.06
$10.85 to $13.30	3,346	1.1	$ 11.95	3,346	$ 11.95
$19.67	16,926	3.4	$ 19.67	16,926	$ 19.67
	30,390			30,390	

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, 2008	40,571	$ 12.81
Granted		$ 0.00
Canceled or expired	(14,286)	$ 8.40
Vested	(16,571)	$ 14.49
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	$ 0.00

As of December 31, 2010, there was $0 of unrecognized compensation cost related to non-vested stock options granted under the 2000 Plan.

Table of Contents

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, 2010:

Years Ending December 31,	Future Minimum Lease Payments
2011	$ 150,777
2012	719
2013	480
	$ 151,976

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

Years Ended December 31,	Lease Expense
2010	$ 115,837
2009	$ 115,557

(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

Our operations are conducted in two principal business segments: (i) pipeline transportation services and (ii) oil and gas exploration and production. Our segments are managed jointly mainly 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

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, 2010 and 2009:

	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.

	Year Ended December 31, 2009			
	Segment			
	Pipeline Transportation	Oil and Gas Exploration & Production	Corporate & Other[1]	Total
Revenues	$ 1,866,971	$ 125,977	$	$ 1,992,948
Operation cost[2]	4,740,912	307,692	367,620	5,416,224
Depletion, depreciation and amortization[3]	420,171	292,809	7,472	720,452
EBIT	$ (3,294,112)	$ (474,524)	$ (375,092)	$ (4,143,728)
Capital expenditures	$ 12,500	$	$	$ 12,500
Identifiable assets[4]	$ 4,634,238	$ 267,713	$ 729,477	$ 5,631,428

(1) Includes unallocated G&A costs associated with corporate maintenance costs and legal expenses. It also includes as identifiable assets corporate available cash of $0.7 million.

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

(3) Includes an impairment charge.

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

Table of Contents

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, 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%
Year Ended December 31, 2009:				
Gryphon Exploration Co.	$	$ 379,828	$ 379,828	20%
W&T Offshore	$	$ 332,396	$ 332,396	18%
Helis Oil & Gas	$	$ 216,047	$ 216,047	12%
Maritech Resources	$	$ 191,512	$ 191,512	10%

We recorded an allowance for doubtful note receivable of $0 and $1,500,000 at December 31, 2010 and 2009, respectively.

(9) 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 Galveston Area Block 321, we recognized gas and oil sales revenue of approximately $48,200 and $26,000 in 2010 and 2009, respectively, and lease operating expenses of approximately $0 and $0 in 2010 and 2009, respectively. 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 115, we recognized gas and oil sales revenue of approximately $48,900 and $57,000 in 2010 and 2009, respectively, and lease operating expenses of approximately $32,900 and $53,000 in 2010 and 2009, respectively. We have a working interest of 2.5% in one zone of a single well in the lease.

Associated with our non-operating interest in High Island Block 37, we recognized gas and oil sales revenue of approximately $45,300 and $43,000 in 2010 and 2009, respectively, and lease operating expenses of approximately $39,500 and $42,000 in 2010 and 2009, respectively. We have a working interest of approximately 2.8% in the block.

Associated with our non-operating interest in the North Sumatra Basin-Langsa Field, we recognized gas and oil sales revenue of approximately $720,300 and $0 in 2010 and 2009, respectively, and lease operating expenses of approximately $601,200 and $0 in 2010 and 2009, respectively. We have a working interest of 7.0% in the oil field.

Table of Contents

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

We retain an independent geologist to provide year-end estimates of our future net recoverable oil and natural gas. Estimated proved net recoverable reserves as shown below include only those quantities that can be expected to be commercially recoverable. Estimated reserves for the year ended December 31, 2010 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 2010, 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

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, 2010 and 2009. Our reserves are located in the U.S. Gulf of Mexico and the North Sumatra Basin in offshore Indonesia. 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.

Quantity of Proved Oil and Gas Reserves	Oil (Bbls)	Natural Gas (Mcf)
Total proved reserves at December 31, 2008	769	158,218
Revisions to previous estimates	239	3,162
Extensions, discoveries, improved recovery and other additions		
Purchase of reserves in place		
Sales of reserves in place		
Production	(250)	(33,531)
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
Proved developed reserves:		
December 31, 2010	30,171	155,484
December 31, 2009	758	127,849
Total proved reserves:		
December 31, 2010	134,122	155,484
December 31, 2009	758	127,849

Table of Contents

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,	
	2010	2009
Unproved properties and prospect generation costs not being amortized	$	$
Proved properties being amortized	2,222,535	1,086,733
Total capitalized costs	2,222,535	1,086,733
Accumulated depreciation, depletion and amortization	(1,063,480)	(868,041)
Net capitalized costs	$ 1,159,055	$ 218,692

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,	
	2010	2009
Costs incurred:		
Acquisition of proved properties	$ 685,714	$
Acquisition of unproved properties		
Exploration costs	58,719	3,143
Development costs		
Total costs incurred	$ 744,433	$ 3,143

Table of Contents

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, 2010	2009
Revenues from oil and gas producing activities	$ 862,685	$ 125,977
Production costs	(673,768)	(95,141)
Depreciation, depletion, and amortization	(195,438)	(89,699)
Impairment of oil and gas properties		(203,110)
Pretax income from producing activities	(6,521)	(261,973)
Income tax expense/estimated loss carryforward benefit	103	4,139
Results of oil and gas producing activities (excluding corporate overhead and interst cost)	$ (6,418)	$ (257,834)

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, 2010	2009
Future cash inflows	$ 11,449,829	$ 529,376
Future development costs	(700,000)	
Future production costs	(3,165,036)	(164,100)
Future income taxes		
10% discount factor	(2,219,392)	(28,980)
Standardized measure of discounted future net cash inflows (outflows)	$ 5,365,401	$ 336,296

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

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,	
	2010	2009
Sales and transfers, net of production costs	$ (188,917)	$ (30,836)
Net change in sales and transfer prices, net of production costs	421,761	(31,511)
Extension, discoveries and improved recovery, net of future production and development costs		
Development costs incurred during the period that reduced future development costs	(45,500)	(32,000)
Changes in estimated future development cost	(32,186)	(29,461)
Revisions of quantity estimates	(39,618)	(1,872)
Accretion of discount	33,630	51,023
Net change in income taxes		
Change in production rates (timing) and other	4,879,935	(99,280)
Net change	$ 5,029,105	$ (173,937)

Remainder of Page Intentionally Left Blank

Table of Contents

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 and Accounting 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, 2010, the Principal Executive Officer and Principal Financial and Accounting 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 and Accounting 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, 2010. 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, 2010, our internal control over financial reporting is effective based on these criteria. This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by our independent registered public accounting firm 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 and Accounting 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

There have been no changes made in our internal control over financial reporting that materially affected, or is reasonably likely to materially affect, the internal control over financial reporting, during the period covered by this report.

Table of Contents

ITEM 9B. OTHER INFORMATION

None.

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 2011 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 2011 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 2011 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 2011 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 2011 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

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 (9)
4.1	Specimen Stock Certificate (2)
4.2	Form of Promissory Note issued pursuant to the Note and Warrant Purchase Agreement dated September 8, 2004 (7)
4.3	Promissory Note of Lazarus Louisiana Refinery II, LLC, payable to Blue Dolphin dated July 31, 2009 (15)
10.1	Blue Dolphin 2000 Stock Incentive Plan (3) *
10.2	First Amendment to the Blue Dolphin 2000 Stock Incentive Plan (4) *
10.3	Second Amendment to the Blue Dolphin 2000 Stock Incentive Plan (5)
10.4	Purchase and Sale Agreement by and between Blue Dolphin Pipe Line Company and MCNIC, dated February 1, 2002 (6)
10.5	Sale of American Resources Offshore, Inc. Common Stock Agreement between Blue Dolphin Exploration Co. and Ivar Siem, dated September 8, 2004 (7)
10.6	Purchase and Sale Agreement by and between Blue Dolphin, WBI Pipeline & Storage Group, Inc. and SemGas LP, dated October 29, 2004 (8)
10.7	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 (10)
10.8	Placement Agency Agreement by and between Blue Dolphin and Starlight Investments, LLC dated May 27, 2005 (12)
10.9	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 (13)
10.10	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 July 31, 2009 (14)
10.11	

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)

* Management Compensation Plan.

** Filed herewith.

No.	Description
10.12	Option Agreement by and among Blue Dolphin Exploration Company, Blue Sky Langsa Limited and Blue Sky Energy and Power Inc. dated July 21, 200. (17)
14.1	Code of Ethics applicable to the Chairman, Chief Executive Officer and Senior Financial Officer (11)
21.1	List of Subsidiaries of Blue Dolphin **
23.1	Consent of UHY LLP **
23.2	Consent of William J. Driscoll, Geologist **
31.1	Ivar Siem Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002 **
31.2	T. Scott Howard Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002 **
32.1	Ivar Siem Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002 **
32.2	T. Scott Howard Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002 **
99.1	Memo from William J. Driscoll, Geologist, regarding Estimated Prove Reserves and Future Revenue **

(1) Incorporated herein by reference to Exhibit 3.1 filed in connection with the Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated June 2, 2009 (Commission File No. 000-15905).

(2) 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 Securities and Exchange Act of 1934, dated March 30, 1990 (Commission File No. 000-15905).

(3) Incorporated herein by reference to Appendix 1 filed in connection with the Proxy Statement of Blue Dolphin under the Securities and Exchange Act of 1934, dated April 20, 2000 (Commission File No. 000-15905).

(4) Incorporated herein by reference to Appendix B filed in connection with the definitive Proxy Statement of Blue Dolphin under the Securities and Exchange Act of 1934, dated April 16, 2003 (Commission File No. 000-15905).

(5) Incorporated herein by reference to Appendix A filed in connection with the definitive Proxy Statement of Blue Dolphin under the Securities and Exchange Act of 1934, dated April 27, 2006(Commission File No. 000-15905).

(6) Incorporated herein by reference to Exhibit 10.20 filed in connection with Form 10-KSB of Blue Dolphin under the Securities and Exchange Act of 1934, dated March 21, 2003 (Commission File No. 000-15905).

(7) Incorporated herein by reference to Exhibit 10.4 filed in connection with Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated September 14, 2004 (Commission File No. 000-15905).

(8) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated November 3, 2004 (Commission File No. 000-15905).

(9) Incorporated herein by reference to Exhibit 3.1 filed in connection with Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated December 26, 2007 (Commission File No. 000-15905).

* Management Compensation Plan.

** Filed herewith.

Table of Contents

(10) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated March 3, 2005 (Commission File No. 000-15905).

(11) 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 Securities Exchange Act of 1934, dated March 25, 2005 (Commission File No. 000-15905).

(12) 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 Securities Exchange Act of 1934, dated March 30, 2006 (Commission File No. 000-15905).

(13) 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 Securities Exchange Act of 1934, dated March 30, 2006 (Commission File No. 000-15905).

(14) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Securities Exchange Act of 1934, dated August 6, 2009 (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 Securities Exchange Act of 1934, 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 Securities Exchange Act of 1934, 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 Securities Exchange Act of 1934, dated July 21, 2010 (Commission File No. 000-15905).

* Management Compensation Plan.

** Filed herewith.

Remainder of Page Intentionally Left Blank

Table of Contents

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/ Ivar Siem
Ivar Siem
Chairman, CEO, President
Assistant Treasurer and Secretary
(Principal Executive Officer)
Date: March 31, 2011

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/ Ivar Siem	Chairman, CEO, President,	March 31, 2011
Ivar Siem	Assistant Treasurer and Secretary (Principal Executive Officer)	
/s/ T. Scott Howard	Treasurer and Assistant Secretary	March 31, 2011
T. Scott Howard	(Principal Financial and Accounting Officer)	
/s/ Laurence N. Benz	Director	March 31, 2011
Laurence N. Benz		
/s/ John N. Goodpasture	Director	March 31, 2011
John N. Goodpasture		
/s/ Harris A. Kaffie	Director	March 31, 2011
Harris A. Kaffie		
/s/ Erik Ostbye	Director	March 31, 2011
Erik Ostbye		

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 (9)
4.1	Specimen Stock Certificate (2)
4.2	Form of Promissory Note issued pursuant to the Note and Warrant Purchase Agreement dated September 8, 2004 (7)
4.3	Promissory Note of Lazarus Louisiana Refinery II, LLC, payable to Blue Dolphin dated July 31, 2009 (15)
10.1	Blue Dolphin 2000 Stock Incentive Plan (3) *
10.2	First Amendment to the Blue Dolphin 2000 Stock Incentive Plan (4) *
10.3	Second Amendment to the Blue Dolphin 2000 Stock Incentive Plan (5)
10.4	Purchase and Sale Agreement by and between Blue Dolphin Pipe Line Company and MCNIC, dated February 1, 2002 (6)
10.5	Sale of American Resources Offshore, Inc. Common Stock Agreement between Blue Dolphin Exploration Co. and Ivar Siem, dated September 8, 2004 (7)
10.6	Purchase and Sale Agreement by and between Blue Dolphin, WBI Pipeline & Storage Group, Inc. and SemGas LP, dated October 29, 2004 (8)
10.7	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 (10)
10.8	Placement Agency Agreement by and between Blue Dolphin and Starlight Investments, LLC dated May 27, 2005 (12)
10.9	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 (13)
10.10	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 July 31, 2009 (14)
10.11	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)
10.11	Option Agreement by and among Blue Dolphin Exploration Company, Blue Sky Langsa Limited and Blue Sky Energy and Power Inc. dated July 21, 2010 (16)

14.1	Code of Ethics applicable to the Chairman, Chief Executive Officer and Senior Financial Officer (11)
21.1	List of Subsidiaries of Blue Dolphin **
23.1	Consent of UHY LLP **

68

Table of Contents

No.	Description
23.2	Consent of William J. Driscoll, Geologist **
31.1	Ivar Siem Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002 **
31.2	T. Scott Howard Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002 **
32.1	Ivar Siem Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002 **
32.2	T. Scott Howard Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002 **
99.1	Memo from William J. Driscoll, Geologist, regarding Estimated Prove Reserves and Future Revenue**

(1) Incorporated herein by reference to Exhibit 3.1 filed in connection with the Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated June 2, 2009 (Commission File No. 000-15905).

(2) 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 Securities and Exchange Act of 1934, dated March 30, 1990 (Commission File No. 000-15905).

(3) Incorporated herein by reference to Appendix 1 filed in connection with the Proxy Statement of Blue Dolphin under the Securities and Exchange Act of 1934, dated April 20, 2000 (Commission File No. 000-15905).

(4) Incorporated herein by reference to Appendix B filed in connection with the definitive Proxy Statement of Blue Dolphin under the Securities and Exchange Act of 1934, dated April 16, 2003 (Commission File No. 000-15905).

(5) Incorporated herein by reference to Appendix A filed in connection with the definitive Proxy Statement of Blue Dolphin under the Securities and Exchange Act of 1934, dated April 27, 2006(Commission File No. 000-15905).

(6) Incorporated herein by reference to Exhibit 10.20 filed in connection with Form 10-KSB of Blue Dolphin under the Securities and Exchange Act of 1934, dated March 21, 2003 (Commission File No. 000-15905).

(7) Incorporated herein by reference to Exhibit 10.4 filed in connection with Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated September 14, 2004 (Commission File No. 000-15905).

(8) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated November 3, 2004 (Commission File No. 000-15905).

(9) Incorporated herein by reference to Exhibit 3.1 filed in connection with Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated December 26, 2007 (Commission File No. 000-15905).

(10) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Securities and Exchange Act of 1934, dated March 3, 2005 (Commission File No. 000-15905).

(11) 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 Securities Exchange Act of 1934, dated March 25, 2005 (Commission File No. 000-15905).

(12) 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 Securities Exchange Act of 1934, dated March 30, 2006 (Commission File No. 000-15905).

(13) 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 Securities Exchange Act of 1934, dated March 30, 2006 (Commission File No. 000-15905).

(14) Incorporated herein by reference to Exhibit 10.1 filed in connection with Form 8-K of Blue Dolphin under the Securities Exchange Act of 1934, dated August 6, 2009 (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 Securities Exchange Act of 1934, 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 Securities Exchange Act of 1934, 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 Securities Exchange Act of 1934, dated July 21, 2010 (Commission File No. 000-15905).

* Management Compensation Plan.

** Filed herewith.