BLUE DOLPHIN ENERGY CO
Form 10-K
April 15, 2010

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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, 2009

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 State or other jurisdiction of incorporation or organization	**73-1268729** (I.R.S. Employer Identification No.)
801 Travis Street, Suite 2100 **Houston, Texas** (Address of principal executive offices)	**77002** (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, 2009 was approximately $3.2 million based on the closing price of $0.42 per share on the NASDAQ Capital Market.
Number of shares of common stock outstanding as of April 14, 2010 11,928,251

DOCUMENTS INCORPORATED BY REFERENCE

Certain sections of the registrant s definitive proxy statement for the 2010 Annual Meeting of Stockholders of the registrant (sections entitled Ownership of Securities of the Company, Election of Directors, Executive Compensation and Transactions With Related Persons), 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, 2009, are incorporated by reference in Part III of this report.

BLUE DOLPHIN ENERGY COMPANY
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PART I

Forward Looking Statements. 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;*
- *ability to regain compliance for continued listing on NASDAQ;*
- *ability to complete a combination with one or more target businesses;*
- *ability to improve pipeline utilization levels;*
- *ability to secure additional working capital to fund operations;*
- *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 Blue Dolphin is subject; and*
- *adverse changes in the global financial markets.*

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 Energy Company, a Delaware corporation formed in 1986, is a holding company and conducts substantially all of its operations through its subsidiaries. We conduct our business activities in two primary business segments: (i) pipeline transportation and related services for producer/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.

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Our principal executive office is located at 801 Travis Street, Suite 2100, Houston, Texas, 77002, and our telephone number is (713) 568-4725. All of our operations are in the Gulf of Mexico, except our onshore facilities which we own and operate to process and store natural gas and liquids to primarily serve our offshore operations. We have six (6) full-time employees and regularly use the services of two (2) consultants. Our common stock, par value $0.01 per share (Common Stock) is 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 Form 10-K.

Recent Developments

The Blue Dolphin Pipeline System (the BDPS) is currently transporting an aggregate of approximately 16 Mcf of gas per day from 8 shippers and the GA 350 Pipeline is currently transporting an aggregate of approximately 22 MMcf of gas per day from 6 shippers. Annual revenues from pipeline operations were $1,866,971 in 2009. Throughput on the BDPS and the GA 350 decreased during 2009 due to normal production declines from the properties owned by companies that use our pipelines to ship their production.

In our oil and gas exploration and production segment, we recognized net oil and gas sales revenues of approximately $43,000 in 2009, associated with our approximate 2.8% working interest in one active well in High Island Block 37. The A-2 Well was restarted in February 2009, after being shut-in as a result of Hurricane Ike. We believe the A-2 Well could continue to produce until early 2012; however, the well could deplete faster than currently projected or could develop production problems resulting in the cessation of production.

We recognized net oil and gas sales revenues of approximately $57,000 in 2009 from our interest in one active well in High Island Block 115. The B-1 ST2 Well first began production in late November 2007. It was shut-in in September 2008, due to damage resulting from Hurricane Ike. Although the well resumed production in the first quarter of 2009, it was shut-in again in August 2009, and currently remains shut-in, due to production handling problems on our downstream production handling platform, High Island Block 71.

We recognized net oil and gas sales revenue of approximately $26,000 from our interest in one active well in Galveston Area Block 321. The A-2 Well was drilled as an exploratory well in December 2008. In January 2009, the well was determined to be economically successful and was connected to the BDPS in the first quarter of 2009.

On March 16, 2010, we were notified by NASDAQ that our common stock is subject to delisting for failure to comply with the minimum bid price listing requirement. We requested, and were granted, a hearing before a NASDAQ Listing Qualifications Panel (the Panel) to appeal the delisting determination. Our common stock will continue to be listed and traded on the NASDAQ Capital Market until the Panel renders a written decision on the matter.

As a means to cure our NASDAQ minimum bid requirement deficiency, on March 16, 2010, our Board of Directors (the Board) adopted, subject to stockholder approval, a Certificate of Amendment to our Certificate of Incorporation, as amended and restated, to implement 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 Board, at any time prior to September 1, 2010.

On July 31, 2009, we issued a $2.0 million non-interest bearing loan (the Loan) to Lazarus Louisiana Refinery II, LLC (LLRII or the Borrower). The Loan, which was 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 and (iii) a guarantee from Lazarus Energy Holdings, LLC (LEH). We agreed to forbear the loan receivable until June 11, 2010, provided the Borrower satisfies certain conditions set forth in the forbearance agreement. Those certain conditions were not met, and on April 9, 2010, we called on the full value of the Loan to be paid by April 13, 2010. As of the date of this report, the Loan is in default and remains unpaid. However, management believes the Loan will be paid at a date in the future. Management is currently pursuing a plan that would include selling the note to a third party. In addition, management plans to begin the necessary steps associated with collection on the collateral. Although this may take time, management feels the Company will recover the full amount of the Loan through this process.

Pipeline Operations and Activities

All of our pipeline assets are held in, and operations conducted by, Blue Dolphin Pipe Line Company.

The table below provides more information on our pipeline segments:

Pipeline Segment	Market	Ownership	Miles of Pipeline	Capacity (MMcf/d)	Storage (Bbls)[1]	Average Throughput (MMcf/d)		
						2009	2008	2007
BDPS	Gulf of Mexico	83.3%	34	160	85,000	15.5	22.6	22.3
GA 350	Gulf of Mexico	83.3%	13	65		19.0	23.8	22.6
Omega[2]	Gulf of Mexico	83.3%	18	110				

(1) Storage facility connected in Freeport, Texas.

(2) Inactive.

The economic return on our pipeline system investments and the fees chargeable for the services provided are dependent upon the amounts of gas and condensate gathered and transported. Currently, the level of throughput on our pipeline systems is significantly below maximum capacity. Competition for provision of gathering and transportation services similar to ours is intense in the market areas we serve. See Markets & Competition for additional information. Since contracts for gathering and transportation services with third party producer/shippers may be for specified time periods, there can be no assurance that current or future producer/shippers will not subsequently tie-in to alternative transportation systems or that current rates charged will be maintained in the future. We actively market our gathering and transportation services to producer/shippers operating in the vicinity of our pipeline systems. Future utilization of the pipelines and related facilities will depend upon the success of drilling programs around our pipelines, and the attraction, and retention, of producer/shippers to the systems. Various fees are charged to producer/shippers for provision of transportation and onshore facility services. Unless otherwise stated, all gas an liquids volumes transported are attributable to production from third party producer/shippers.

Blue Dolphin Pipeline System The BDPS includes: the Blue Dolphin Pipeline, an offshore platform, the Buccaneer Pipeline, onshore facilities for condensate 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 pipeline system s onshore facilities, pipeline easements and rights-of-way are located. We own an 83% undivided interest in the BDPS. The BDPS gathers and transports gas and condensate from various offshore fields in the Galveston Area of the 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.

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The Blue Dolphin Pipeline consists of two segments, an offshore segment and an onshore segment. The offshore segment transports both gas and condensate 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 condensate from the onshore facility storage tanks to our barge-loading terminal on the Intracoastal Waterway near Freeport, Texas for sale to third parties. The Blue Dolphin Pipeline has an aggregate capacity of approximately 160 MMcf of gas and 7,000 Bbls of crude oil and condensate per day.

Galveston Area Block 350 Pipeline We own an 83% undivided interest in the Galveston Area Block 350 Pipeline (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.

Other We also own an 83% undivided interest in a third offshore pipeline, the Omega Pipeline, which is currently inactive. 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. Reactivation of the Omega Pipeline will be dependent upon future drilling activity in the vicinity and successfully attracting producer/shippers to the system.

Oil and Gas Exploration and Production Activities

Although we sold substantially all of our producing oil and gas properties in 2002, we continue our oil and gas exploration and production activities, which include the exploration, acquisition, development, operation and, when appropriate, disposition of oil and gas properties. We focus our oil and gas activities in the western Gulf of Mexico off the Texas coast. We currently own seismic and other data that may be used to evaluate and develop prospects, including a non-exclusive license to approximately 200 blocks of 3-D seismic data covering 1,152,000 acres in the western Gulf of Mexico and a substantial inventory of close grid 2-D seismic data. Our oil and gas assets are held by Blue Dolphin Petroleum Company.

The leasehold interests we hold in properties are subject to royalty, overriding royalty and interests of others.

Oil and Gas Exploration and Production Assets and Activities. The following is a description of our oil and gas exploration and production assets and activities:

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, which began production in March 2009. The well is currently 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. We own a 0.5% overriding royalty interest in the well. The lease is operated by Maritech Resources.

High Island Block 115 High Island Block 115 is located approximately 30 miles southeast of Bolivar Peninsula in an average water depth of approximately 38 feet. The block contains one active well, the B-1 ST2 Well. The well has been shut-in since August 2009 due to production handling problems on our downstream production handling platform, High Island Block 71. We are exploring

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options with the lease operator to resolve the production handling issues. We own a 2.5% working interest in a single production zone in the well. The lease is operated by Republic Petroleum.

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. Production from the A-2 Well was restarted in February 2009, after being shut-in as a result of Hurricane Ike. The B-1 Well is currently shut-in following an unsuccessful workover in September 2009. We own an approximate 2.8% working interest in this lease that covers 5,760 acres. The lease is operated by Hilcorp Energy Company.

Productive Wells

	Producing Wells		Non-Producing Wells	
Region	Gross Wells	Net Wells	Gross Wells	Net Wells
Gulf of Mexico Oil and gas	2.0	0.1		
Total	2.0	0.1		

Developed Acreage

	Non-Producing Wells	
Region	Gross Acreage	Net Acreage
Gulf of Mexico Oil and gas	11,520	310
Total	11,520	310

We have no undeveloped oil and gas leases.

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

Proved Oil and Gas Reserves. 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 attached as an exhibit to this report. All reserve definitions comply with the definitions of Rules 4-10(a)(1)-(32) of SEC Regulation 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 revenues attributable thereto.

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Estimates of production and future net revenues cannot be expected to represent accurately the actual production or revenues 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 revenues and costs incurred in our oil and gas activities and the discounted present value of estimated future net revenues from our proved reserves.

The following table presents the estimates of proved reserves, proved developed reserves (as hereinafter defined) and the discounted present value of future net revenues or expenses from proved reserves after income taxes (in thousands) to our net interest in oil and gas properties as of December 31, 2009. The discounted present value of future net revenues 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 Reserves
As of December 31, 2009(1) (2)

	Net Oil Reserves (Mbbls)	Net Gas Reserves (MMcf)	Present Value of Future Net Cash Inflows (Outflows)(1) (in thousands)
Proved Reserves			
Galveston Area Block 321	0.1	4	$ 19
High Island Block 115	0.6	112	293
High Island Block 37	0.1	12	24
Total Proved Reserves	0.8	128	$ 336
Proved Developed			
Galveston Area Block 321	0.1	4	$ 19
High Island Block 115	0.6	112	293
High Island Block 37	0.1	12	24
Total Proved Developed	0.8	128	$ 336

(1) The estimated present value of future net cash outflows from our proved reserves has been determined by using prices of $61.08 per barrel of oil and $3.78 per Mcf of gas, 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).

(2) As of December 31, 2009, we reported no proved undeveloped reserves.

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 President. We provide 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 President 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, 2009 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,				
	2010	2011	2012	2013	2014
Galveston Area Block 321					
High Island Block A-7		$238			
High Island Block 37				$68	
High Island Block 115					$37

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

Net Production, Price and Cost Data

	Years Ended December 31,		
	2009	2008	2007
Gas:			
Production (Mcf)	33,630	44,700	72,788
Revenue	$ 108,576	$ 526,522	$ 476,224
Average production per day (Mcf) (*)	92.1	122.5	199.4
Average sales price per Mcf	$ 3.23	$ 11.78	$ 6.54
Condensate:			
Production (Bbls)	250	117	177
Revenue	$ 17,401	$ 14,057	$ 10,345
Average production per day (Bbls) (*)	0.7	0.3	0.5
Average sales price per Bbl	$ 69.60	$ 120.25	$ 58.45
NGLs:			
Production (gallons)			36,372
Revenue	$	$	$ 30,842
Average production per day (gallons) (*)			99.7
Average sales price per gallon	$	$	$ 0.85
Production costs (**):			
Per Mcfe:	$ 2.71	$ 5.36	$ 3.04

(*) 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 Activity. There was no drilling activity in 2009.

	Net Exploratory(1)		
	2009	2008	2007
Wells Drilled			
Gulf of Mexico			
Productive			
Dry		1	
		1	

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

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Customers

We generated revenues from both of our business segments. Gryphon Exploration, W&T Offshore, Helis Oil & Gas and Maritech Resources for approximately 20%, 18%, 12% and 10%, respectively, of our revenues in 2009. Revenues from customers exceeding 10% of revenues were as follows for 2009 and 2008:

	Oil and Gas Sales	Pipeline Operations	Total
Year Ended December 31, 2009:			
Gryphon Exploration Co.	$	$ 379,828	$ 379,828
W&T Offshore	$	$ 332,396	$ 332,396
Helis Oil & Gas	$	$ 216,047	$ 216,047
Maritech Resources	$	$ 191,512	$ 191,512
Year Ended December 31, 2008:			
Arena Offshore	$	$ 513,634	$ 513,634
W&T Offshore	$	$ 488,083	$ 488,083
Gryphon Exploration Co.	$	$ 367,153	$ 367,153
Apex Oil & Gas	$	$ 338,836	$ 338,836

Markets & Competition

The availability of a ready market for oil and natural gas, and the prices of oil and natural gas, depends upon a number of factors which are beyond our control. These include, among other things:

- the level of domestic 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 affecting the supply and demand for crude oil, condensate, natural gas and refined petroleum products, it is not possible to predict accurately the prices or marketability of the oil and natural gas produced for sale or prices chargeable for transportation and storage services, which we provide. Our sale of natural gas is generally made at the market prices at the time of sale. Therefore, even though we sell natural gas to major purchasers, we believe other purchasers would be willing to buy our natural gas at comparable market prices.
Vigorous competition occurs among oil, gas and other energy sources, and between producers, transporters, and distributors of oil and gas. Our pipeline business faces competition from other pipelines in the markets that we serve. The principal elements of competition among pipelines are rates, terms of service, access to markets, flexibility and reliability of service. Our oil and natural gas business competes 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 these competitors are large, well-established companies that have financial and other resources that are substantially greater than ours, which give them an advantage over us in evaluating and obtaining properties and prospects. Our ability to acquire additional pipelines and oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. There is also competition for the hiring of experienced personnel to manage and operate our assets. Several highly competitive alternative transportation and delivery options exist for current and potential customers of our traditional gas and oil gathering and transportation business. Competition also exists with other industries in supplying the energy and fuel needs of consumers.

Governmental Regulation

The production, processing, marketing, and transportation of oil and gas by us are subject to federal, state and local regulations which can have a significant impact upon our overall operations.

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 did not alter our non-FERC-jurisdictional status, but has greatly expanded FERC s authority, including enforcement authority against market manipulation in connection with FERC-jurisdictional transactions. FERC has undertaken vigorous enforcement actions against a number of entities, including those not subject to direct FERC regulation, and, 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. Thus 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. In February 2007, FERC issued a policy order acknowledging its lack of jurisdiction over offshore gathering, but stating that FERC would intervene in the event that interstate pipelines with affiliated offshore gathering lines engage in anticompetitive behavior, such 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.

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.

Safety and Operational Regulations. Our operations are generally subject to safety and operational regulations administered primarily by the United States Minerals Management Service (MMS), the U.S. Department of Transportation, the U.S. Coast Guard, FERC and/or various state agencies. In addition, the OCSLA authorizes regulations relating to safety and environmental protection applicable to leases 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. All of our exploration and production operations are currently located on federal oil and gas leases in the OCS, which are administered by the MMS. Such leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the OCSLA that are subject to interpretation and change by the MMS. For offshore operations, lessees must obtain MMS 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, lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS 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, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurance that such obligations will be met. The cost of these 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 the MMS. Under some circumstances, the MMS 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 conducted on offshore federal leases, liability may generally be imposed under OCSLA for costs of clean-up and damages caused by pollution resulting from such operations, other than 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, the MMS may also require any of our operations on federal leases to be suspended or terminated in the affected area. Furthermore, the MMS generally requires that offshore facilities be dismantled and removed within one year after production ceases or the lease expires.

Environmental Regulation. Our activities with respect to (1) exploration, development and production of oil and natural gas and (2) the operation and construction of pipelines, plants, and other facilities for the transportation and processing, and storage of oil and natural gas are subject to stringent environmental regulation by local, state and federal authorities, including the U.S. Environmental Protection Agency (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 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. It is not anticipated that, in response to such regulation, we will be required in the near future 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 responsible parties with respect to 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 or arranged for the disposal of a hazardous substance at the site, 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. At this time, neither we nor any of our predecessors have been designated as a potentially responsible party under CERCLA.

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 for offshore facilities of all removal costs plus $75 million, and 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 cleanup, liability limits likewise 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 type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges, worst-case spill potential and other factors. We believe we have established adequate financial responsibility. While the financial responsibility requirements under OPA may be amended to impose additional costs on us, the impact of such a change is not expected 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 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 of America 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 on 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 (CCA) establishes the Texas Coastal Management Program that applies in the nineteen Texas counties that border the Gulf of Mexico and its tidal bays. The CCA 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 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 this statutory $35 million coverage.

Federal and state legislative rules and regulations are pending that, if enacted, could significantly affect the oil and gas industry. It is impossible to predict which of those federal and state proposals and rules, if any, will be adopted and what effect, if any, they would have on our operations.

In addition, 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, expenses and costs. The trend in such regulation 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. It is not anticipated that, in response to such regulation, we will be required in the near future to expend amounts that are material relative to our total capital structure. However, it is possible that the costs of compliance with environmental and health and safety laws and regulations will continue to increase. Given the frequent changes made to environmental and health and safety regulations and laws, we are unable to predict the ultimate cost of compliance.

Employees

We have six (6) full-time employees and regularly use the services of two (2) consultants. Our employees, along with the engineering and geological expertise provided by our consultants, supervise and coordinate the operation and administration of our oil and gas properties, pipelines and other assets. From time to time, major maintenance, engineering and construction projects are contracted to third-party engineering and service companies.

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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 April 15, 2010 are listed below:

Name	Office	Officer Since	Age
Ivar Siem	Chairman of the Board and Chief Executive Officer	1989	63
Thomas W. Heath	President, Secretary and Assistant Treasurer	2007	47
T. Scott Howard	Treasurer and Assistant Secretary	2008	38

Ivar Siem, has served as Chairman of the Board of Directors of the Company since 1989 and was appointed as Chief Executive Officer in 2004. 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.

Thomas W. Heath was appointed as President and Secretary of the Company in 2009, having previously served as Executive Vice President since 2007. From 2004 to 2007 he served as a Vice President of Union Bank of California, N.A., an affiliate of Bank of Tokyo-Mitsubishi UFJ, Ltd., where he developed and implemented an energy derivatives desk supporting Energy Capital Services. From 1988 to 2004 Mr. Heath held a variety of management and executive level positions with the evolving marketing units of Acadian Gas Pipeline System, Coral Energy, L.P. (formerly Shell Trading Gas & Power), Sempra Energy Trading Corp. and Tejas Gas Corporation. Mr. Heath began his career in 1983 with Columbia Gulf Transmission Company where he served in various operational and commercial positions until 1988. He is an alumnus of the University of Houston.

T. Scott Howard was appointed as Treasurer of the Company in 2009 and Assistant Secretary of the Company in April 2008. He joined the Company 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.

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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 is reasonably possible after these reports are filed with the Securities and Exchange Commission (SEC). Information about each of our Board members, 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.

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

Risks Related to our Business

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

We incurred a net loss of $4,136,892 for the year ended December 31, 2009, and a net loss of $1,966,240 for the year ended December 31, 2008. We have not had a profitable year since 2006. As of December 31, 2009, we had an accumulated deficit of $30,107,651. We anticipate that we will continue to incur substantial operating losses and may require additional financing in the foreseeable future. These matters raise substantial doubt as to our ability to continue as a going concern. Existing and anticipated working capital needs, lower than anticipated revenues, increased expenses or the inability to collect on an outstanding Loan to the Borrower could all affect 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, in the Notes to Consolidated Financial Statements included in this annual report, these circumstances raise substantial doubt about our ability to continue as a going concern. Our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles (GAAP), contemplate that we will continue as a going concern and do not contain any adjustments that might result if we were unable to continue as a going concern. This report may make it more difficult for us to raise additional capital necessary to operate our business.

If the $2.0 million loan receivable remains unpaid, we could deplete our cash reserves by the end of the third quarter of this year.

On July 31, 2009, we issued a Loan to the Borrower. The Loan, which was due on January 31, 2010, is secured by (i) a first lien on property owned by LEN, (ii) a second lien on property owned by LLRII and (iii) a guarantee from LEH. We agreed to forbear the loan receivable until June 11, 2010, provided the Borrower satisfies certain conditions set forth in the forbearance agreement. Those certain conditions were not met, and on April 9, 2010, we called on the full value of the Loan to be paid by April 13, 2010. As of the date of this report, the Loan is in default and remains unpaid. However, management believes the Loan will be paid at a date in the future. Management is currently pursuing a plan that would include selling the note to a third party. In addition, management plans to begin the necessary steps associated with collection on the collateral. Although this may take time, management feels the Company will recover the full amount of the Loan through this process.

Our cash flow projections suggest that, should the Loan remain unpaid, we could deplete our cash reserves by the end of the third quarter of this year.

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

For the year ended December 31, 2009, approximately 94% of our revenues were derived from our pipeline operations and the limited amount of reserves on properties we currently own interests in. We expect that our future revenues will continue to be primarily dependent on the level of use of our pipeline systems. Various factors can influence the level of use of our pipeline systems, 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 to attract new producer/shippers to our pipeline systems. 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. Our working interests are in properties in the Gulf of Mexico where, generally, the rate of production declines more rapidly than in many other producing areas of the world. As the level of production from these properties continues to decline, our revenue from oil and gas sales will decrease. Revenues from oil and gas sales accounted for approximately 6% of our total revenues in 2009 and 18% in 2008. Unless we are able to replace production revenue with revenue from interests in other oil and gas properties, increase the level of utilization of our pipelines or acquire other revenue generating assets at an acceptable cost, our revenues and cash flow from operations will decrease and our financial condition will be materially adversely affected.

A significant decrease in exploration and production activity in areas where our pipelines are, the decline in production from existing wells, depressed commodity prices or otherwise, would adversely affect our revenues and cash flow.

The profitability of our pipeline operations is materially impacted by the volume of throughput. A material decrease in production in our areas of operation would result in a further decline in our throughput volumes. We have no control over many factors affecting production activity, including prevailing and projected commodity prices, demand for oil and gas, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. The level of throughput on our pipelines is significantly below maximum capacity. Failure to connect new wells to our pipelines would result in the amount of throughput being reduced further over time. Our ability to connect to new wells will be dependent on the level of drilling activity in our areas of operations, the success of that drilling activity and competitive market factors. The effect of any decrease in the throughput handled by our pipelines would reduce our revenues and operating income.

If we are not able to generate sufficient funds from our operations and other financing sources, we may not be able to finance our operations.

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.

Continued underutilization of our pipelines, low commodity prices, production problems, declines in production, disappointing drilling results and other factors beyond our control could further reduce our funds from operations. Additionally, we project that our current cash reserves will be sufficient to meet our obligations through the third quarter of this year. As a result we may have to seek debt and equity financing to meet our working capital requirements. Our history of losses may affect our ability to raise additional capital, or increase the cost of obtaining financing. In addition, additional capital at acceptable terms may not be available to us in the future. In the event we are not able to raise additional capital, we may be forced to sell some, or all, of our assets at unfavorable terms or on an untimely basis.

The global financial crisis may have impacts 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 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 revenues.

If our common stock fails to meet the listing requirements of NASDAQ and 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. The NASDAQ s listing requirements include a requirement that, for continued listing, an issuer s common shares trade at a minimum bid price of $1.00 per share. This requirement is deemed breached when the bid price of an issuer s common shares closes below $1.00 per share for 30 consecutive trading days. On September 16, 2009, we were notified by the NASDAQ Listing Qualifications Department (Listing Qualifications) that our shares failed to meet the requirement for the specified time period and they could initiate steps to delist our common stock from trading on the NASDAQ anytime after March 15, 2010, unless our closing bid price exceeds $1.00 per share for at least 10 consecutive trading days prior to that date. As a result of not regaining compliance within the specified compliance period, on March 16, 2010 Listing Qualifications notified us that, unless we requested a hearing before the Panel to appeal Listing Qualifications delisting determination, our common stock would be suspended from trading and cease being listed on the NASDAQ Capital Market on March 25, 2010. We timely requested a hearing before the Panel, which stayed the delisting determination, pending a final written decision by the Panel. There can be no assurance that we will be successful in maintaining our listing on NASDAQ or the trading market for our common stock. A delisting of our common stock from the NASDAQ could adversely affect the liquidity of the trading market for our stock and therefore the market price of our common stock. If NASDAQ determines to delist our common stock and our common stock is not eligible for quotation on another market or exchange, trading of ours common stock could be conducted in the over-the-counter market or on an electronic bulletin board established for unlisted securities such as the Pink Sheets or the OTC Bulletin Board. In such event, it could become more difficult to dispose of, or obtain accurate quotations for the price of our common stock, and there would likely also be a reduction in our coverage by security analysts and the news media, 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 shares of our common stock without further depressing the market price of our common stock or at all. A delisting of our common stock also could make it more difficult for us to obtain financing for the continuation of our operations.

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

All of our assets are located in the Western Gulf of Mexico and the onshore Gulf Coast of Texas. Because our assets are not as diversified geographically as many of our competitors, our business is subject to local conditions more than other, more geographically diversified companies. Any regional event, including price fluctuations, natural disasters and restrictive regulations that increase costs may adversely impact our business more than if our assets were geographically diversified.

Oil and gas prices are volatile and a substantial and extended decline in the price of oil and gas would have a material adverse effect on us.

The tightening of natural gas supply and demand fundamentals has resulted in extremely volatile natural gas prices, and this volatility in natural gas prices is expected to continue. Our revenues, profitability, operating cash flow and our potential for growth are largely dependent on prevailing oil and natural gas prices. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include:

- weather conditions in the United States;
- the condition of the United States economy;
- the actions of the Organization of Petroleum Exporting Countries;
- 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

generally impairing our ability to obtain needed capital.

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We face strong competition from larger companies that may negatively affect our ability to carry on operations.

We operate in a highly competitive industry. Our competitors include major integrated oil companies, substantial 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:

- most of our competitors have greater financial resources than we do, which gives them better access to capital to acquire assets; and

- we sometimes establish a higher standard for the minimum projected rate of return on invested capital than some of our competitors since we cannot afford to absorb certain risks. We believe this puts us at a competitive disadvantage in acquiring pipelines and 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 regarding oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;

- the interpretation of that data;

- the accuracy of various mandated economic assumptions; and

- the judgment of the persons preparing the estimate.

The proved reserve information set forth in this report is based on estimates 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, 2009. 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, other companies operate or control the development of the oil and gas properties in which we have an interest. As a result, we depend on the operator of the wells or leases to properly conduct lease acquisition, drilling, completion and production operations. The failure of an operator, or the drilling contractors and other service providers selected by the operator to properly perform services, or an operator s failure to act in ways that are in our best interest, could adversely affect us, including the amount and timing of revenues, if any, we receive from 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, for example, 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 to pursue, acquisitions. Our business may be adversely affected if we cannot effectively integrate acquired operations.

One of our business strategies has been to acquire operations and assets that are complementary to our existing businesses. Acquiring operations and assets involves financial, operational and legal risks. These risks include:

- 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 to pay and reduce our acquisition opportunities. We are often out-bid by larger, better capitalized companies for acquisition opportunities 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 those operations, such as:

- 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 peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

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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 over 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 as well as re-drilling expenses and pollution coverage for wells out of control.

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 that is not fully insured or indemnified against occurs, it could materially and adversely affect our financial condition and results of operations.

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 six (6) full-time employees and regularly use the services of two (2) consultants, both of whom are former employees. Success within our existing two business segments pipeline operations and activities and oil and gas exploration and production activities will depend 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 we use regularly, both of whom are also former employees with a long history with the Company. 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 recruitment and retention of qualified personnel in key areas. We may not be able to attract and retain required personnel on acceptable terms due to the competition for experienced personnel from other companies in the industry.

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

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

- require the acquisition of a permit before operations can be commenced;
- 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, but 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 OPA 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 OPA, could have a material adverse impact on us.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information appearing in Item 1 describing our oil and gas properties, pipelines and other assets under the caption Description of Business 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.

ITEM 3. LEGAL PROCEEDINGS

We are a party to litigation that is incidental to our business; however, neither we nor any of our property is subject to any material pending legal proceedings.

ITEM 4. RESERVED

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 April 14, 2010, we had 492 stockholders of record. Based on information collected with respect to our annual meeting of stockholders held on May 14, 2009, we estimate that there are approximately 2,000 beneficial holders of our common stock.

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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	Low
2009		
December 31, 2009	$0.62	$0.29
September 30, 2009	$0.58	$0.39
June 30, 2009	$0.79	$0.36
March 31, 2009	$0.45	$0.26
2008		
December 31, 2008	$0.85	$0.32
September 30, 2008	$2.20	$0.75
June 30, 2008	$2.57	$1.25
March 31, 2008	$1.95	$1.15

On March 16, 2010, we were notified by NASDAQ that our common stock is subject to delisting for failure to comply with the minimum bid price listing requirement. We requested, and were granted, a hearing before the Panel to appeal the delisting determination. Our common stock will continue to be listed and traded on the NASDAQ Capital Market until the Panel renders a written decision on the matter.

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 our Board of Directors 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.

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Compensation Plan Information

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2009, under which our equity securities were authorized for issuance:

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	424,559	$ 2.53	351,040
Equity compensation plans not approved by security holders		$ 0.00	
Total	424,559	$ 2.53	351,040

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Item 6. SELECTED FINANCIAL DATA
Financial information by quarter is summarized below:

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
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	$ (0.09)	$ (0.06)	$ (0.03)	$ (0.17)	$ (0.35)
2008					
Revenue from operations:					
Pipeline operations	$ 547,817	$ 695,402	$ 561,171	$ 644,441	$ 2,448,831
Oil and gas sales	130,720	293,553	120,108	(3,802)	540,579
Total revenue from operations	678,537	988,955	681,279	640,639	2,989,410
Cost of operations:					

Pipeline operating expenses	415,956	402,096	415,581	489,009	1,722,642
Lease operating expenses	50,173	83,094	40,710	69,473	243,450
Depletion, depreciation and amortization	131,338	117,690	164,689	114,255	527,972
Impairment of oil and gas properties				213,563	213,563
General and administrative expenses	561,625	489,364	426,342	476,165	1,953,496
Stock based compensation	72,184	72,184	75,222	78,685	298,275
Accretion expense	28,576	26,733	26,356	26,355	108,020
Total cost of operations	1,259,852	1,191,161	1,148,900	1,467,505	5,067,418
Other income (expense), including income tax expense	55,941	26,727	24,884	4,216	111,768
Net loss	$ (525,374)	$ (175,479)	$ (442,737)	$ (822,650)	$ (1,966,240)
Loss per share: Basic and diluted	$ (0.05)	$ (0.02)	$ (0.04)	$ (0.07)	$ (0.17)

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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 assets are located offshore and onshore in the Texas Gulf Coast area. Our goal is to create greater long-term value for our stockholders by increasing the utilization of our existing pipeline assets and acquiring additional strategic assets that diversify our asset base, improve our competitive position and are accretive to earnings. Although we are primarily focused on acquisitions of pipeline assets and maximizing our current facilities, we also continue to review, evaluate opportunities and acquire additional oil and gas properties.

Pipeline Transportation. The BDPS is currently transporting an aggregate of approximately 16 MMcf of gas per day from 8 shippers. The GA 350 Pipeline is currently transporting an aggregate of approximately 22 MMcf of gas per day from 6 shippers.

Oil and Gas Exploration and Production

Galveston Area Block 321 The well is currently 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. We own a 0.5% overriding royalty interest in the well. The lease is operated by Maritech Resources.

High Island Block 115 The block contains one active well, the B-1 ST2 Well, which has been shut-in since August 2009 due to production problems on our downstream production handling platform, High Island Block 71. We are exploring options with the lease operator to resolve the production handling issues. We own a 2.5% working interest in a single production zone in the well. The lease is operated by Republic Petroleum.

High Island Block 37 The block contains one active well, the A-2 Well, and one inactive well, the B-1 Well. Production from the A-2 Well was restarted in February 2009, after being shut-in as a result of Hurricane Ike. The B-1 Well is currently shut-in following an unsuccessful workover in September 2009. We own an approximate 2.8% working interest in this lease that covers 5,760 acres. The lease is operated by Hilcorp Energy Company.

Our pipeline assets remain significantly under-utilized. The BDPS is currently operating at approximately 10% of capacity, the GA 350 Pipeline is currently operating at approximately 34% of capacity and the Omega Pipeline remains inactive. Production declines, temporary stoppages or cessations of production from wells tied into our pipelines or from our working and overriding royalty interests in wells in Galveston Area and High Island blocks as noted herein could have a material adverse effect on our cash flows and liquidity if the resulting revenue declines are not offset by revenues 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.

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Results of Operations

For the year ended December 31, 2009 (current period), we reported a net loss of $4,136,892, compared to a net loss of $1,966,240 for the year ended December 31, 2008 (previous period). For the three months ended December 31, 2009 (the current quarter), we reported a net loss of $2,065,248 compared to a net loss of $822,650 for the three months ended December 31, 2008 (the previous quarter).

2009 Compared to 2008

Revenue from Pipeline Operations. Revenues from pipeline operations decreased by $581,860, or 24%, in the current period to $1,866,971 primarily due to decreases in volumes transported. Revenues in the current period from the BDPS totaled approximately $1,498,000 compared to approximately $2,042,000 in the previous period primarily due to natural production declines. Daily gas volumes transported through the BDPS averaged approximately 16 MMcf of gas per day in the current period compared to approximately 23 MMcf of gas per day in the previous period. Revenues on the GA 350 Pipeline decreased by approximately $38,000 to approximately $369,000 in the current period primarily due to natural production declines. Average daily gas volumes for GA 350 transported decreased to approximately 19 MMcf of gas per day in the current period from approximately 24 MMcf of gas per day in the previous period.

Revenue from Oil and Gas Sales. Revenues from oil and gas sales decreased by $414,602, or 77%, to $125,977 in the current period primarily due to lower commodity prices and one of our producing wells, the B-1 ST-2 in High Island Block 115, being off production for five months.

Our average realized gas price per Mcf in the current period was $3.23 compared to $11.78 in the previous period. The sales mix by product was 86% gas and 14% condensate. Our average realized price per barrel of condensate was $69.60 in the current period compared to $120.25 in the previous period. Revenue breakdown for the current period by field was approximately $43,000 for High Island Block 37, $57,000 for High Island Block 115 and $26,000 for Galveston Area Block 321.

Pipeline Operating Expenses. Pipeline operating expenses decreased by $207,280 to $1,515,362 in the current period. The decrease was primarily due to a decrease in storage tank repairs and lower compressor repair, insurance, chemical, legal and salt water transportation expenses. These decreases were partially offset by increases in other repairs primarily as a result of Hurricane Ike and crane repair expense.

Lease Operating Expenses. Lease operating expenses decreased $148,309, or 61%, in the current period to $95,141 primarily due to one of our producing wells, the B-1 ST-2 in High Island Block 115, being off production for five months and a reclassification of lease operating expense to plugging and abandonment costs.

Impairment of Oil and Gas Properties. During the first quarter of the current period we recorded a full cost ceiling impairment of $203,110. A variety of economic and other factors caused significant declines in oil and gas prices. We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the ceiling, based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves, calculated using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. Our ceiling was calculated using prices of $47.19 per barrel of oil and $3.65 per MMbtu. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation, resulting in a write-down of our oil and natural gas properties.

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General and Administrative Expenses, and Stock Based Compensation. These expenses decreased $56,893 in the current period to $2,194,878 primarily due to decreases in officer salaries, other salaries, property and directors and officers insurance. These decreases were partially offset by increases in legal fees and office expenses.

Interest and Other Income. Other income decreased by $108,262 in the current period due to a decrease in interest income.

Three Months Ended December 31, 2009 Compared to Three Months Ended December 31, 2008

Revenue from Pipeline Operations. Revenues from pipeline operations decreased by $283,114, or 44%, in the current quarter to $361,327 primarily due to decreases in volumes transported. Revenues in the current quarter from the BDPS decreased to approximately $280,000 compared to approximately $548,000 in the previous quarter. Daily gas volumes transported on the BDPS averaged 13 MMcf of gas per day in the current quarter compared to 25 MMcf of gas per day in the previous quarter. Revenues on the GA 350 Pipeline decreased to approximately $81,000 compared to approximately $97,000 in the previous quarter due to a decrease in average daily gas volumes transported of 16 MMcf of gas per day in the current quarter from 22 MMcf of gas per day in the previous quarter.

Revenue from Oil and Gas Sales. Revenues from oil and gas sales increased by $21,489 in the current quarter primarily due to the interruption of production at our producing properties in the previous quarter as a result of Hurricane Ike.

Pipeline Operating Expenses. Pipeline operating expenses in the current quarter decreased by $241,063 to $247,946 primarily due to decreases in storage tank repairs, barge dock repairs, consulting expense, insurance expense and other repairs.

Lease Operating Expenses. Lease operating expenses decreased in the current quarter by $52,768 to $16,705 due to decreased production at our producing properties.

General and Administrative Expenses and Stock Based Compensation. These expenses decreased by $150,605 to $404,245 in the current quarter primarily due decreases in officer salaries, legal fees and consulting expense.

Interest and Other Income, Including Income Tax. Interest and other income decreased by $131,322 primarily due to the reverse against the previously recorded consulting income associated with a one year consulting agreement with Lazarus Energy Holdings, LLC.

Liquidity and Capital Resources

Sources and Uses of Cash. Our primary source of cash is cash flow from operations. During 2009, we had negative cash flow from operations of approximately $1.5 million, excluding working capital changes, mainly due to low utilization of our pipeline systems and decreased production at our producing properties.

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. Our current available cash is $1.0 million at December 31, 2009.

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	For Year Ended December 31, (in millions)	
	2009	2008
Cash flow from operations		
Loss from operations	$ (1.5)	$ (0.7)
Change in current assets and liabilities	0.4	0.1
Total cash flow from operations	(1.1)	(0.6)
Cash outflows		
Capital expenditures and advance of loan receivable	(1.5)	(0.8)
Payments on note payable	(0.2)	
Total cash outflows	(1.7)	(0.8)
Total change in cash flows	$ (2.8)	$ (1.4)

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. Our consolidated financial statements, which have been prepared in accordance with GAAP, contemplate that we will continue as a going concern and do not contain any adjustments that might result if we were unable to continue as a going concern. We incurred a net loss of $4,136,892 for the year ended December 31, 2009. As of December 31, 2009, we had an accumulated deficit of $30,107,651. We anticipate that we will continue to incur substantial operating losses unless and until we are able to achieve or sustain profitability. Our 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 revenues, increased expenses or the inability to collect on an outstanding loan receivable could all affect 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 annual report, these circumstances raise substantial doubt about our ability to continue as a going concern.

We intend to raise additional working capital through private placements, 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.

The continuation of our business is dependent upon obtaining additional financing. 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. There are no assurances that we will be able to raise additional capital through private placement, public offerings and/or bank financing necessary to support our working capital requirements. We do not currently have any agreements in place to raise any additional capital.

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

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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, 2009 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 under utilized and such underutilization is an indicator of possible impairment at December 31, 2009. Accordingly, we developed future cash flows as of December 31, 2009 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 increasing current leasing and drilling activities, and prospective drilling activity surrounding our pipelines. 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 has been recorded as of December 31, 2009.

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 and relocate or dispose of our offshore platforms, pipeline systems and related onshore facilities, plugging and abandonment of wells and restoration costs of land and seabed. We develop estimates of these costs for each of our assets based upon regulatory requirements, the type of platform structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. 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 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, 2009. 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 effective for annual periods beginning after December 15, 2010. We do not expect the adoption of this guidance to have a material impact on our consolidated financial statements.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

None.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements:

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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, 2009 and 2008, 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, 2009. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Blue Dolphin Energy Company and Subsidiaries as of December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2009 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
April 15, 2010

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,016,483	$ 3,864,876
Accounts receivable, net of allowance for doubtful accounts	428,124	442,715
Loan receivable, net of allowance for loan receivable		
Prepaid expenses and other current assets	359,850	436,242
Total current assets	1,804,457	4,743,833
Property and equipment, at cost:		
Oil and gas properties (full-cost method)	1,086,733	1,286,700
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	302,813	290,313
	8,828,909	9,016,376
Less: Accumulated depletion, depreciation and amortization	5,011,401	4,494,059
Total property and equipment, net	3,817,508	4,522,317
Other assets	9,463	9,463
Total assets	$ 5,631,428	$ 9,275,613
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 372,275	$ 389,268
Note payable insurance	173,479	
Accrued expenses and other liabilities	8,136	9,593
Other long-term liabilities current portion	25,996	25,996
Total current liabilities	579,886	424,857
Long-term liabilities:		
Asset retirement obligations, net of current portion	2,262,018	2,183,190
Other long-term liabilities, net of current portion		25,996
Total long-term liabilities	2,262,018	2,209,186
Total liabilities	2,841,904	2,634,043

Commitments and contingencies		
Stockholders equity:		
Common stock ($.01 par value, 100,000,000 shares authorized, 11,876,967 and 11,691,243 shares issued and outstanding at December 31, 2009 and 2008, respectively)	118,770	116,912
Additional paid-in capital	32,778,405	32,495,417
Accumulated deficit	(30,107,651)	(25,970,759)
Total stockholder s equity	2,789,524	6,641,570
Total liabilities and stockholders equity	$ 5,631,428	$ 9,275,613

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Statements of Operations

	Years Ended December 31, 2009	2008
Revenue from operations:		
Pipeline operations	$ 1,866,971	$ 2,448,831
Oil and gas sales	125,977	540,579
Total revenue from operations	1,992,948	2,989,410
Cost of operations:		
Pipeline operating expenses	1,515,362	1,722,642
Lease operating expenses	95,141	243,450
Depletion, depreciation and amortizaton	517,342	527,972
Impairment of oil and gas properties	203,110	213,563
Allowance for doubtful note receivable, net of consulting agreement	1,500,000	
General and administrative expenses	1,990,032	1,953,496
Stock-based compensation	204,846	298,275
Accretion expense	110,843	108,020
Total cost of operations	6,136,676	5,067,418
Loss from operations	(4,143,728)	(2,078,008)
Other income (expense):		
Interest and other income	9,921	120,069
Loss on disposal of assets		(1,886)
Total other income (expense)	9,921	118,183
Loss before income taxes	(4,133,807)	(1,959,825)
Income tax expense	(3,085)	(6,415)
Net loss	$ (4,136,892)	$ (1,966,240)
Loss per common share:		
Basic	$ (0.35)	$ (0.17)
Diluted	$ (0.35)	$ (0.17)
Weighted average number of common shares outstanding:		
Basic	11,785,747	11,642,391

Diluted	11,785,747	11,642,391

See accompanying notes to consolidated financial statements.

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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, 2007	11,610,363	$ 116,104	$ 32,117,950	$ (24,004,519)	$ 8,229,535
Common stock issued for services	80,880	808	79,192		80,000
Stock-based compensation			298,275		298,275
Net loss				(1,966,240)	(1,966,240)
Balance at December 31, 2008	11,691,243	$ 116,912	$ 32,495,417	$ (25,970,759)	$ 6,641,570
Common stock issued for services	185,724	1,858	78,142		80,000
Stock-based compensation			204,846		204,846
Net loss				(4,136,892)	(4,136,892)
Balance at December 31, 2009	11,876,967	$ 118,770	$ 32,778,405	$ (30,107,651)	$ 2,789,524

See accompanying notes to consolidated financial statements.
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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Years Ended December 31, 2009	2008
OPERATING ACTIVITIES		
Net loss	$ (4,136,892)	$ (1,966,240)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depletion, depreciation and amortization	517,342	527,972
Impairment of oil and gas properties	203,110	213,563
Accretion expense	110,843	108,020
Stock-based compensation	204,846	298,275
Common stock issued for services	80,000	80,000
Allowance for doubtful note receivable, net of consulting agreement	1,500,000	
Bad debt expense		26,699
Loss on disposal of assets		1,886
Changes in operating assets and liabilities:		
Accounts receivable	14,591	224,563
Prepaid expenses and other current assets	450,013	73,452
Abandonment costs incurred	(32,015)	(18,537)
Accounts payable, accrued expenses and other liabilities	(44,446)	(169,737)
Net cash used in operating activities	(1,132,608)	(600,084)
INVESTING ACTIVITIES		
Advance of loan receivable, net of consulting agreement	(1,500,000)	
Exploration and development costs	(3,143)	(749,088)
Capital expenditures	(12,500)	(12,731)
Net cash used in investing activities	(1,515,643)	(761,819)
FINANCING ACTIVITIES		
Payments on notes payable	(200,142)	
Net cash used in financing activities	(200,142)	
Decrease in cash and cash equivalents	(2,848,393)	(1,361,903)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	3,864,876	5,226,779
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 1,016,483	$ 3,864,876
Non-cash investing and financing activities:		
Financing of insurance premiums	$ 373,621	$
Consulting agreement associated with loan receivable	$ 500,000	$

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements

(1) Organization and Significant Accounting Policies

Organization

Blue Dolphin Energy Company 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. 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.

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. 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 generally accepted accounting principles (GAAP), contemplate that we will continue as a going concern and do not contain any adjustments that might result if we were unable to continue as a going concern. We incurred a net loss of $4,136,892 for the year ended December 31, 2009. As at December 31, 2009, we had an accumulated deficit of $30,107,651. We anticipate that we will continue to incur substantial operating losses unless and until we are able to achieve or sustain profitability or are otherwise able to secure external financing. Our 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 revenues, increased expenses or the inability to collect on an outstanding loan receivable could all affect our ability to continue as a going concern.

We intend to raise additional working capital through private placements, 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.

The continuation of our business is dependent upon obtaining such further financing. 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. There are no assurances that we will be able to obtain additional financing through private placement, public offerings and/or bank financing necessary to support our working capital requirements. We do not currently have any arrangements in place to raise any additional funds.

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

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. 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 Federal Deposit Insurance Corporation increased its insurance from $100,000 to $250,000 per depositor. The coverage increase, which is temporary, extends through December 13, 2013. Additionally, coverage for non-interest bearing accounts, which is temporary, is unlimited and extends through June 30, 2010.

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 utilize one cost center for all of our properties. Amortization of such costs and estimated future development costs is determined using the unit-of-production method. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties or impairment has occurred.

Estimated proved oil and gas reserves are based upon reports prepared internally by us. 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 revenues from proved reserves, after giving effect to income taxes, and the lower of cost or estimated fair value of unproved properties. In 2009, our unamortized cost exceeded the present value of estimated future net revenues and we recorded an impairment to our oil and gas properties of $203,110. Disposition of oil and gas properties are 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.

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

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

In August 2001, FASB issued amended guidance on accounting for asset retirement obligations, which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset.

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

We have asset retirement obligations associated with the future abandonment of pipelines and related facilities and offshore oil and gas properties. The following table summarizes our asset retirement obligation transactions during the years ended December 31, 2009 and 2008 (in thousands).

	Years Ended December 31,	
	2009	2008
Beginning asset retirement obligations	$ 2,183	$ 2,094
Liabilities incurred		
Liabilities settled	(32)	(19)
Accretion expense	111	108
Ending asset retirement obligations	$ 2,262	$ 2,183

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, 2009 was not material.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Recognition of Pipeline Transportation Revenue

Revenues from our pipelines are derived from fee-based contracts and are 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.

Subsequent Events

In May 2009, the FASB established general standards of accounting for and disclosures of events that occur subsequent to the balance sheet date but before financial statements are issued or available to be issued. The guidance is effective for interim and annual periods ending after June 15, 2009. The adoption of this guidance did not have a material impact on our consolidated financial statements. We evaluated all subsequent events through the issuance date of our consolidated financial statements as of and for the 12 month period ended December 31, 2009, and during this subsequent period no material subsequent events occurred that would require recognition or disclosure in these consolidated financial statements, except for the allowance for the loan receivable.

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 effect on the results of operations in the period in which such changes or events occur. The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for individual customer balances. As of December 31, 2009 and 2008, we had recorded an allowance for doubtful accounts of $0 and $26,699, respectively, related to accounts receivable.

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.

We evaluate our tax positions in a two-step process. The first step is to determine whether it is more likely than not that a tax position will be sustained upon examination. The second step is a measurement process whereby a tax position that meets the more-likely-than-not threshold is calculated to determine the amount of benefit to recognize in the financial statements.

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

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, 2009 and 2008, 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	2009	2008
Net loss	$ (4,136,892)	$ (1,966,240)
Weighted average number of shares of common stock outstanding and potential dilutive shares of common stock	11,785,747	11,642,391
Per share amount	$ (0.35)	$ (0.17)

Environmental

We are subject to extensive federal, state and local 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.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

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 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 effective for annual periods beginning after December 15, 2010. We do not expect the adoption of this guidance to have a material 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.

(3) Loan Receivable

On July 31, 2009, we issued a $2.0 million non-interest bearing loan (the Loan) to Lazarus Louisiana Refinery II, LLC (LLRII or the Borrower). The Loan, which was 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 and (iii) a guarantee from Lazarus Energy Holdings, LLC (LEH). We agreed to forbear the loan receivable until June 11, 2010, provided the Borrower satisfies certain conditions set forth in the forbearance agreement. Those certain conditions were not met, and on April 9, 2010, we called on the full value of the Loan to be paid by April 13, 2010. As of the date of this report, the Loan is in default and remains unpaid. Although management believes the Loan could be paid in full at a date in the future, we reserved an allowance for the entire $2.0 million balance of the Loan as of December 31, 2009, and expensed $1.5 million (net of $500,000 for the consulting agreement).

A $500,000 one year consulting agreement that commenced on July 1, 2009, was also associated with the loan receivable. As of December 31, 2009, we reserved the remaining $250,000 of deferred consulting revenue and reserved against the $250,000 of previously recognized consulting revenue.

(4) Income Taxes

Income tax expense consisted of $3,085 and $6,415 and was related to state income tax for the years ended 2009 and 2008, respectively.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

The income tax effects of temporary differences that give rise to significant portions of deferred tax assets and deferred tax liabilities at December 31, 2009 and 2008 are presented below:

	2009	2008
Deferred tax assets:		
Net operating loss and capital loss carryforwards	$ 7,029,596	$ 5,881,885
AMT credit carryforward	11,564	11,564
Basis differences in property and equipment	470,908	314,192
Total deferred tax assets	7,512,068	6,207,641
Less: valuation allowance	(7,512,068)	(6,207,641)
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, 2009 and 2008 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, 2009 and 2008 was an increase of $1,304,427 and $343,660, respectively.

Our effective tax rate applicable to continuing operations in 2009 and 2008 is as follows:

	Years Ended December 31,	
	2009	2008
Expected tax rate	(34.00%)	(34.00%)
Change in valuation allowance recognized in earnings	34.07%	34.33%
	0.07%	0.33%

For federal tax purposes, we have net operating loss carry-forwards (NOLs) of approximately $20.7 million at December 31, 2009. These NOLs must be utilized prior to their expiration, which will occur between 2011 and 2029.

We adopted FASB s guidance on 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 in accordance with FASB s guidance on accounting for income taxes. 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 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-

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

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 on accounting for uncertainty in income taxes have been applied to all of our material tax positions taken through the date of adoption and through the fiscal year ended December 31, 2009. 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 new pronouncement.

In May 2006, the State of Texas enacted a new business tax that is imposed on gross revenues to replace the State s current franchise tax regime. Although the Texas margins tax (TMT) is imposed on an entity s gross revenues 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, the Company records 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, 2009 and 2008. Furthermore, none of the Company s federal and state income tax returns are currently under examination by the Internal Revenue Service (IRS) or state authorities, but fiscal years 2005 and later remain subject to examination by the IRS and the State of Texas. The Company believes that it has no uncertain tax positions for both federal and state income taxes.

(5) Stock Options

Effective April 14, 2000, after approval by our stockholders, we adopted the 2000 Stock Incentive Plan (the 2000 Plan). Under the 2000 Plan, we are able to make awards of stock-based compensation. The number of shares of common stock reserved for grants of incentive stock options (ISOs) and other stock-based awards was increased to 1,200,000 shares after approval by our stockholders during 2007. As of December 31, 2009, we had 341,040 shares of common stock remaining available for future grants. Options granted under the 2000 Plan have contractual terms 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 determined on the grant date. All ISO awards granted in previous years vested immediately, however, 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 our Board of Directors.

A tax deduction is permitted for stock options exercised during the period, generally for the excess of the price at which stock issued from exercise of the options are sold over the exercise price of the options. Tax benefits are to be shown on the Statement of Cash Flows as financing cash inflows. Any tax deductions we receive from the exercise of stock options for the foreseeable future will be applied to the valuation allowance in determining our net operating loss carry forward.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

Additionally, we utilized 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. The following assumptions were used to determine the fair value of stock options granted during the years ended December 31, 2009 and 2008. There were no options granted during the year ended December 31, 2009.

	Year Ended December 31, 2008
Stock options granted	75,000
Risk-free interest rate	3.23%
Expected term, in years	6.00
Expected volatility	90.70%
Dividend yield	0.00%

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 past two years prior to the grant date. This weighting method was chosen to account for the significant changes in our financial condition beginning approximately three years ago. These changes include the decrease in our working capital, decreased pipeline throughput and 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 the SEC s 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.

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

At December 31, 2009, there were a total of 424,559 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, 2009					
	Shares		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life		Aggregate Intrinsic Value
Options outstanding at December 31, 2007	491,559	$	2.61			
Options granted	75,000	$	1.36			
Options exercised		$	0.00			
Options expired or cancelled	(11,000)	$	3.10			
Options outstanding at December 31, 2008	555,559	$	2.43			
Options granted		$	0.00			
Options exercised		$	0.00			
Options expired or cancelled	(131,000)	$	2.13			
Options outstanding at December 31, 2009	424,559	$	2.53	5.4	$	
Options exercisable at December 31, 2009	356,559	$	2.44	5.0	$	

The following table summarizes additional information about stock options outstanding at December 31, 2009:

	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
$0.35 to $0.80	70,830	3.3	$	0.44	70,830	$	0.44
$1.36 to $1.90	23,429	2.1	$	1.71	23,429	$	1.71
$2.81 to $2.99	318,500	6.3	$	2.92	250,500	$	2.90
$6.00	11,800	0.4	$	6.00	11,800	$	6.00
	424,559				356,559		

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

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, 2007	350,000	$ 2.05
Granted	75,000	$ 1.03
Canceled or expired		$ 0.00
Vested	(141,000)	$ 2.00
Non-vested at December 31, 2008	284,000	$ 1.83
Granted		$ 0.00
Canceled or expired	(100,000)	$ 1.20
Vested	(116,000)	$ 2.07
Non-vested at December 31, 2009	68,000	$ 2.35

As of December 31, 2009, there was $52,582 of unrecognized compensation cost related to 68,000 non-vested stock options granted under the 2000 Plan. The weighted average period over which the unrecognized compensation cost will be recognized is 4 months.

(6) Leases

We have various operating leases that extend through April 2017. Certain of these operating leases are non-cancelable through May 2010. The following is a schedule of future minimum lease payments under non-cancelable operating leases exceeding one year at December 31, 2009:

Years Ending December 31,	Future Minimum Lease Payments
2010	172,646
	$ 172,646

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

Years Ended December 31,	Lease Expense
2009	$ 115,557
2008	$ 116,117

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

Pursuant to the terms of a letter agreement dated October 9, 2009, the initial term of an employment agreement effective May 1, 2007, was extended from three years to four years. The employment agreement provides for a base salary of $175,000 per year.

(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 the size of the Company. Our management uses 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.

Below is a reconciliation of our EBIT (by segment) for each of the years ended December 31, 2009 and 2008:

	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[4]	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[3]	$ 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 revenues.

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

(4) Includes an impairment charge.

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

	December 31, 2008			
	Segment			
	Pipeline Transportation	Oil and Gas Exploration & Production	Corporate & Other[1]	Total
Revenues	$ 2,448,831	$ 540,579	$	$ 2,989,410
Operation cost[2]	3,389,058	594,247	342,578	4,325,883
Depletion, depreciation and amortization	417,384	317,618	6,534	741,536
EBIT	$ (1,357,611)	$ (371,286)	$ (349,112)	$ (2,078,009)
Capital expenditures	$ 1,033	$ 749,088	$ 11,698	$ 761,819
Identifiable assets[3]	$ 5,073,147	$ 560,221	$ 3,642,245	$ 9,275,613

(1) Includes unallocated G&A costs associated with corporate maintenance costs and legal expenses. It also includes as identifiable assets corporate available cash of $3.5 million.

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

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

assets.

Our primary market area is the Texas and Louisiana Gulf Coast region of the United States. We have a concentration of credit risk with customers in the energy 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. Revenues from major customers exceeding 10% of revenues were as follows for the period indicated:

	Oil and Gas Sales	Pipeline Operations	Total
Year Ended December 31, 2009:			
Gryphon Exploration Co.	$	$ 379,828	$ 379,828
W&T Offshore	$	$ 332,396	$ 332,396
Helis Oil & Gas	$	$ 216,047	$ 216,047
Maritech Resources	$	$ 191,512	$ 191,512
Year Ended December 31, 2008:			
Arena Offshore	$	$ 513,634	$ 513,634
W&T Offshore	$	$ 488,083	$ 488,083
Gryphon Exploration Co.	$	$ 367,153	$ 367,153
Apex Oil & Gas	$	$ 338,836	$ 338,836

As of December 31, 2009, we recorded an allowance for doubtful note receivable of $1,500,000, net of a consulting agreement.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
(9) Supplemental Oil and Gas Information

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 High Island Block 37, we recognized gas and oil sales revenues of approximately $43,000 and $250,000 in 2009 and 2008, respectively, and lease operating expenses of approximately $42,000 and $127,000 in 2009 and 2008, respectively. We have a working interest of approximately 2.8% in the block.

Associated with our non-operated interest in High Island Block 115, we recognized gas and oil sales revenues of approximately $57,000 and $290,000 in 2009 and 2008, respectively, and lease operating expenses of approximately $53,000 and $116,000 in 2009 and 2008, respectively. We have a working interest of 2.5% in one zone of a single well in the lease.

Associated with our non-operated interest in Galveston Area Block 321, we recognized gas and oil sales revenues of approximately $26,000 and $0 in 2009 and 2008, respectively, and lease operating expenses of approximately $0 and $0 in 2009 and 2008, respectively. We have an overriding royalty interest of 0.5% in an exploratory well in the lease.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

The Company retains an independent geologist to provide year-end estimates of the Company s 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, 2009 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 2009, 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.

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, 2009 and 2008. All of our reserves are located within the United States of America. 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 which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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

Quantity of Oil and Gas Reserves	Oil (Bbls)	Gas (Mcf)
Total proved reserves at December 31, 2007	846	177,671
Revisions to previous estimates	(297)	10,827
Extensions, discoveries, improved recovery and other additions	337	14,440
Purchase of reserves in place		
Sales of reserves in place		
Production	(117)	(44,720)
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
Proved developed reserves:		
December 31, 2009	758	127,849
December 31, 2008	769	158,218
Total proved reserves:		
December 31, 2009	758	127,849
December 31, 2008	769	158,218

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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, 2009	December 31, 2008
Unproved properties and prospect generation costs not being amortized	$	$
Proved properties being amortized	1,086,733	1,286,700
Total capitalized costs	1,086,733	1,286,700
Accumulated depreciation, depletion and amortization	(868,041)	(776,467)
Net capitalized costs	$ 218,692	$ 510,233

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, 2009	Years Ended December 31, 2008
Costs incurred:		
Acquisition of proved properties	$	$
Acquisition of unproved properties		
Exploration costs	3,143	749,088
Development costs		
Total costs incurred	$ 3,143	$ 749,088

We did not incur costs in the acquisition of oil and gas properties in 2009 or 2008.

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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 revenues, general and administrative expenses, interest expense and interest income.

	Years Ended December 31, 2009	2008
Revenues from oil and gas producing activities	$ 125,977	$ 540,579
Production costs	(95,141)	(243,450)
Depreciation, depletion, and amortization	(89,699)	(104,055)
Impairment of oil and gas properties	(203,110)	(213,563)
Pretax income from producing activities	(261,973)	(20,489)
Income tax expense/estimated loss carryforward benefit	4,139	324
Results of oil and gas producing activities (excluding corporate overhead and interest costs)	$ (257,834)	$ (20,165)

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, 2009	2008
Future cash inflows	$ 529,376	$ 866,563
Future development costs		
Future production costs	(164,100)	(267,932)
Future income taxes		
10% discount factor	(28,980)	(88,398)
Standardized measure of discounted future net cash inflows (outflows)	$ 336,296	$ 510,233

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).

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.

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

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 Securities Exchange Commission 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,	
	2009	2008
Sales and transfers, net of production costs	$ (30,836)	$ (297,129)
Net change in sales and transfer prices, net of production costs	(31,511)	(377,061)
Extension, discoveries and improved recovery, net of future production and development costs		404,129
Development costs incurred during the period that reduced future development costs	(32,000)	18,500
Changes in estimated future development cost	(29,461)	67,296
Revisions of quantity estimates	(1,872)	(27,964)
Accretion of discount	51,023	10,700
Net change in income taxes		241,740
Change in production rates (timing) and other	(99,280)	762
Net change	$ (173,937)	$ 40,973

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

None.

ITEM 9A(T). 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 Chief 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, 2009, the Chief 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 Chief 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, 2009. 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, 2009, 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 registered public accounting firm pursuant to temporary rules of the SEC that permit us to provide only management s report in this annual report.

Our management, including our Chief 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.

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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 2010 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 2010 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 RELATE

The information required by Item 12 is incorporated by reference to our definitive proxy statement relating to our 2010 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 2010 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 2010 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.

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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 the Company (1)
3.2	Amended and Restated By-Laws of the Company (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 Energy Company dated July 31, 2009 (15)
10.1	Blue Dolphin Energy Company 2000 Stock Incentive Plan (3) *
10.2	First Amendment to the Blue Dolphin Energy Company 2000 Stock Incentive Plan (4) *
10.3	Second Amendment to the Blue Dolphin Energy Company 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 Energy Company, 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 Energy Company and Starlight Investments, LLC dated May 27, 2005 (12)
10.9	Form of Stock Purchase Agreement between Blue Dolphin Energy Company 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 Energy Company dated July 31, 2009 (14)
14.1	Code of Ethics applicable to the Chairman, Chief Executive Officer and Senior Financial Officer (11)

* Management Compensation Plan.

** Filed herewith.

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No.	Description
21.1	List of Subsidiaries of the Company **
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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company under the Securities and Exchange Act of 1934, dated March 23, 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company for the year ended December 31, 2004 under the Securities Exchange Act of 1934, dated March 25, 2005 (Commission File No. 000-15905).

* Management Compensation Plan.

** Filed herewith.

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(12) Incorporated herein by reference to Exhibit 10.9 filed in connection with Form 10-KSB of Blue Dolphin Energy Company 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 Energy Company 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 Energy Company 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 Energy Company under the Securities Exchange Act of 1934, dated August 6, 2009 (Commission File No. 000-15905).

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SIGNATURES

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

BLUE DOLPHIN ENERGY COMPANY
(Registrant)

By: /s/ Ivar Siem
Ivar Siem
(Chairman and CEO)

Date: April 15, 2010

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 Ivar Siem	Chairman and CEO (Principal Executive Officer)	April 15, 2010
/s/ T. Scott Howard T. Scott Howard	Treasurer and Assistant Secretary (Principal Financial and Accounting Officer)	April 15, 2010
/s/ Laurence N. Benz Laurence N. Benz	Director	April 15, 2010
/s/ John N. Goodpasture John N. Goodpasture	Director	April 15, 2010
/s/ Harris A. Kaffie Harris A. Kaffie	Director	April 15, 2010
/s/ Erik Ostbye Erik Ostbye	Director	April 15, 2010

Exhibit Index

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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 Energy Company dated July 31, 2009 (14)
14.1	Code of Ethics applicable to the Chairman, Chief Executive Officer and Senior Financial Officer (11)
21.1	List of Subsidiaries of the Company **
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 **

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No.	Description
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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company under the Securities and Exchange Act of 1934, dated March 23, 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company 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 Energy Company under the Securities Exchange Act of 1934, dated August 6, 2009 (Commission File No. 000-15905).