BLUE DOLPHIN ENERGY CO
Form 10KSB
March 31, 2008

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

þ **Annual Report Under Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2007

o **Transition Report Under Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from __________ to __________

Commission file Number: 0-15905
BLUE DOLPHIN ENERGY COMPANY
(Name of small business issuer in its charter)

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

Issuer s telephone number **(713) 227-7660**
Securities registered pursuant to Section 12(b) of the Exchange Act: **common stock, par value $.01 per share**
Securities registered pursuant to Section 12(g) of the Exchange Act: **none**
(Title of Class)

Check whether the issuer is not required to file reports pursuant to Section 13 or 15 (d) of the Exchange Act. o

Check whether the issuer (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 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

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B contained in this form, and no disclosure will 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-KSB or any amendment to this Form 10-KSB. þ

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

The issuer s revenues for the year ended December 31, 2007 were $3,011,817.

The aggregate market value of the common stock, par value $.01 per share, held by non-affiliates of the registrant as of March 26, 2008, based on the last reported trading price of the registrant s common stock on the NASDAQ Capital Market on that date, was approximately $16,025,000.

As of March 26, 2008, there were 11,624,447 shares of common stock, par value $.01 per share, of the issuer outstanding.

Documents Incorporated By Reference

Certain sections of the registrant s definitive proxy statement for the 2008 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, 2007, are incorporated by reference in Part III of this report.

Transitional Small Business Disclosure Format. Yes o No þ

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List of Subsidiaries of the Company
Consent of UHY LLP
Certification of Ivar Siem Pursuant to Section 302
Certification of Gregory W. Starks Pursuant to Section 302
Certification of Ivar Siem Pursuant to Section 906
Certification of Gregory W. Starks Pursuant to Section 906

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PART I

Forward Looking Statements. Certain of the statements included in this annual report on Form 10-KSB, 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 events 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:

- *the level of utilization of our pipelines;*
- *availability and cost of capital;*
- *actions or inactions of third party operators for properties where we have an interest;*
- *the risks associated with oil and gas exploration;*
- *the level of production from oil and gas properties that we have interests in;*
- *gas and oil price volatility;*
- *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;*
- *regulatory developments; and*
- *general economic conditions.*

Additional factors that could cause actual results to differ materially from those indicated in the forward-looking statements are discussed under the caption 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. Description of 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; and
- Blue Dolphin Services Co., a Texas 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) 227-7660. We maintain shore-based facilities in Freeport, Texas, to serve our Gulf of Mexico operations. We have eight employees and two consultants. Our 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 properties, are defined in the Glossary of Certain Oil and Gas Terms of this Form 10-KSB.

Recent Developments

The Blue Dolphin System is currently transporting an aggregate of approximately 26 MMcf of gas per day from ten shippers and the GA 350 Pipeline is currently transporting an aggregate of approximately 29 MMcf of gas per day from six shippers. Annual revenues from pipeline operations were $2,494,406 in 2007. Throughput on the Blue Dolphin System and the GA 350 Pipeline increased significantly during 2007 due to production gains from three shippers delivering production from a total of four wells. Delivery of production from two of the wells commenced on the Blue Dolphin System and two of the wells commenced on the GA 350 Pipeline. Since the beginning of 2006, the Blue Dolphin System and the GA 350 Pipeline have gained production from seven shippers delivering from eight wells. Four of these shippers are delivering production into the Blue Dolphin System, representing five wells, and three of the shippers are delivering production into the GA 350 Pipeline from three wells. In 2007, a shipper began deliveries into the Blue Dolphin System from two wells in July. On the GA 350 Pipeline, one shipper began deliveries in each of June and September of 2007.

In 2007, in addition to the throughput gains received from shippers added to the pipelines, the Blue Dolphin System also benefited from the drilling activities of an existing shipper. In June 2007, an existing shipper drilled a new well, resulting in an increase of daily production.

Production from the High Island Block 37 A-2 well was restarted in December 2007 after experiencing production problems in April 2007. The well was shut in for approximately eight months. High Island Block 37 averaged approximately 5.4 MMcf of gas per day in 2007 as compared to approximately 15.6 MMcf of gas per day in 2006. We recognized gross oil and gas sales revenues of approximately $276,000 in 2007 associated with our approximate 2.8% working interest in High Island Block 37. The High Island Block 37 A-2 well is currently producing at a rate of approximately 3 MMcf of gas per day. The B-1 well experienced production problems in January 2008 and is currently shut-in. We believe that the A-2 well could continue to produce until mid-2008, however, the well could deplete faster than currently anticipated or could develop production problems resulting in the cessation of production. Additional development of reserves in this block is currently being evaluated.

The well in High Island Block 115 commenced production in late November 2007 and produced at an average rate of approximately 6.3 MMcf per day during the remainder of 2007. We had previously earned a 2.5% working interest in this well, which was drilled successfully in the second quarter 2007. We recognized gross oil and gas sales revenues of approximately $30,000 from this well in 2007. The well is currently producing at a rate of approximately 9 MMcf of gas per day.

The High Island Block A-7 well also experienced production problems in the second quarter 2007. The well has produced only intermittently since. It is currently shut in and may have reached the end of its productive life. The well averaged approximately 0.7 MMcf of gas per day in 2007 as compared to approximately 5.6 MMcf of gas per day in 2006. We recognized gross oil and gas sales revenues of approximately $211,000 for the twelve months ended December 31, 2007 associated with our approximate 8.9% working interest in the High Island Block A-7 well.

Pipeline Operations and Activities

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

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 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 the pipelines, and the attraction, and retention, of producer/shippers to the systems.

Blue Dolphin Pipeline System. The Blue Dolphin Pipeline System (the Blue Dolphin System) 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 shore facilities, pipeline easements and rights-of-way are located. We own an 83% undivided interest in the Blue Dolphin System. The Blue Dolphin System gathers and transports gas and condensate from various offshore fields in the Galveston Area of the Gulf of Mexico to shore facilities located in Freeport, Texas. After processing, the gas is transported to an end user and a major intrastate pipeline system with further downstream tie-ins to other intrastate and interstate pipeline systems and end users.

The Blue Dolphin Pipeline 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 shore facility to a sales point at a Freeport, Texas chemical plants complex and intrastate pipeline system tie-in. 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.

Various fees are charged to producer/shippers for provision of transportation and shore facility services. The Blue Dolphin System has an aggregate capacity of approximately 160 MMcf of gas per day and 7,000 Bbls of crude oil and condensate per day. Gas throughput for the Blue Dolphin System averaged 22.3 MMcf of gas per day, or approximately 14% of capacity, and 17.3 MMcf of gas per day, or approximately 9% of capacity during 2007 and 2006, respectively. The Blue Dolphin System is currently transporting approximately 26 MMcf of gas per day. All gas and liquids volumes transported in 2007 and 2006 were attributable to production from third party producer/shippers.

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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. Gas throughput for the GA 350 Pipeline averaged 22.6 MMcf of gas per day, or approximately 35% of capacity, and 9.0 MMcf of gas per day, or approximately 14% of capacity, during 2007 and 2006, respectively. The pipeline is currently transporting approximately 29 MMcf of gas per day. All gas and liquids volumes transported were attributable to production from third party producer/shippers.

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 coast of Texas. 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.

The following is a description of our oil and gas exploration and production assets and activities:

High Island Block 37. High Island Block 37 is located approximately 15 miles south of Sabine Pass, offshore Texas, in an average water depth of approximately 36 feet. We own an approximate 2.8% working interest in this lease that covers 5,760 acres. The lease contains two producing wells which are operated by Seneca Resources Corporation. The B-1 well is currently shut-in. The A-2 well is currently producing approximately 3 MMcf of gas per day. We recorded gross revenues from sales of oil and natural gas in High Island Block 37 of approximately $276,000 and $890,000 for the years ended December 31, 2007 and 2006, respectively.

High Island Block A-7. High Island Block A-7 is located approximately 33 miles southeast of Bolivar Peninsula, offshore Texas, in an average water depth of approximately 39 feet. We own an approximate 8.9% working interest in this lease that covers 5,760 acres. The lease is operated by Hydro Gulf of Mexico, LLC (formerly Spinnaker Exploration Company). The single producing well in this block produced an average of 0.7 MMcf of gas per day during 2007 as a result of production problems experienced in the second quarter. The well is currently shut-in and may have reached the end of its productive life. During the years ended December 31, 2007 and 2006, we recorded gross revenues from oil and natural gas sales of approximately $211,000 and $1,469,000, respectively, from this field.

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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. We own a 2.5% working interest in a single production zone in one well in this lease. Production commenced in late November 2007. In 2007, we recognized gross revenues from oil and natural gas sales of approximately $30,000 from this well. The well is currently producing approximately 9 MMcf of gas per day.

See Note (12), Business Segment Information, in Item 7 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. We have prepared estimates of proved reserves, and discounted present value of future net revenues to our net interest as of December 31, 2007.

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.

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 (13), Supplemental Oil and Gas Information, in Item 7 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.

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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, 2007. 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, 2007 (1)(2)

	Net Oil Reserves (Mbbls)	Net Gas Reserves (MMcf)	Present Value of Future Net Cash Inflows (Outflows) After Income Taxes (1)
Total Proved Reserves			
High Island Block A-7	0.0	0	$ (166)
High Island Block 37	0.0	18	6
High Island Block 115	0.8	160	629
	0.8	178	$ 469
Total Proved Developed			
High Island Block A-7	0.0	0	$ (166)
High Island Block 37	0.0	18	6
High Island Block 115	0.8	160	629
	0.8	178	$ 469

(1) The estimated present value of future net cash outflows after income taxes from our proved reserves has been determined by using prices of $88.46 per barrel of oil and $7.13 per Mcf of gas, representing the December 31, 2007 prices for oil and gas and discounted at a 10% annual rate

in accordance with requirements for reporting oil and gas reserves pursuant to regulations promulgated by the United States Securities and Exchange Commission (the SEC Method).

(2) As of December 31, 2007, we reported no proved undeveloped reserves.

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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 (in thousands).

ESTIMATED UNDISCOUNTED CAPITAL EXPENDITURES
ASSOCIATED WITH PLUGGING AND ABANDONMENT OF WELLS

	Years Ending December 31,				
	2008	2009	2010	2011	2012
High Island Block A-7	265				
High Island Block 37		92			
High Island Block 115				39	

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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,		
	2007	2006	2005
Gas:			
Production (Mcf)	72,788	312,146	378,791
Revenue	$ 476,224	$ 2,131,415	$ 3,071,811
Average production per day (Mcf) (*)	199.4	772.3	1,037.8
Average sales price per Mcf	$ 6.54	$ 6.83	$ 8.11
Condensate:			
Production (Bbls)	177	1,823	781
Revenue	$ 10,345	$ 114,114	$ 40,481
Average production per day (Bbls) (*)	0.5	5.0	2.1
Average sales price per Bbl	$ 58.45	$ 62.60	$ 51.83
NGLs:			
Production (gallons)	36,372	137,139	27,935
Revenue	$ 30,842	$ 113,285	$ 23,718
Average production per day (gallons) (*)	99.7	375.7	76.5
Average sales price per gallon	$ 0.85	$ 0.83	$ 0.85
Production costs (**):			
Per Mcfe:	$ 3.04	$ 1.34	$ 0.40

(*) Average production is based on a 365 day year. However, 2005 average production per day contains 549 days of production for High Island Block 37.

(**) Production costs, exclusive of workover costs, are costs incurred to operate and maintain wells and equipment and to pay production

taxes.
Drilling Activity. During the third quarter of 2007, a single well in High Island Block 115 was successfully recompleted. After laying flowlines to the well, production commenced in late November 2007. The rate of production from this well averaged 6.3 MMcf of gas per day through the end of 2007. We did not incur any capital expenditures associated with this recompletion since the obligations associated with our working interest did not commence until flow was established.

Employees

We have a total of eight employees and two consultants. Our employees are capable of supervising and coordinating the operation and administration of our oil and gas properties and pipeline 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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Customers

We generated revenues from both of our primary business segments. Apex Oil & Gas, W&T Offshore and Gryphon Exploration Co. accounted for approximately 26.8%, 17.2% and 11.3%, respectively, of our revenues in 2007. Revenues from customers exceeding 10% of revenues were as follows for 2007 and 2006:

	Oil and Gas Sales	Pipeline Operations	Total
Year Ended December 31, 2007:			
Apex Oil & Gas	$	$ 809,420	$ 809,420
W&T Offshore	$	$ 519,866	$ 519,866
Gryphon Exploration Co.	$	$ 341,406	$ 341,406
Year Ended December 31, 2006:			
Hydro Gulf of Mexico, LLC (formerly Spinnaker Exploration Company)	$ 1,469,132	$	$ 1,469,132
Fidelity Exploration and Production Company	$ 889,682	$	$ 889,682

Competition

Both segments of our business are highly competitive. 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 and have financial and other resources 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.

Markets

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

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- 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.

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 Natural Gas Act and Natural Gas Policy Act 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. Additionally, energy pricing has attracted renewed political interest. Thus Congress could reenact price controls in the future. The rates, terms and conditions applicable to interstate transportation of gas by pipelines are regulated by the 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). The 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 the 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 the 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

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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, the 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 (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.

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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.

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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 groundwaters. 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

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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.

RISK FACTORS

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

As a result of our sale of substantially all of our proved oil and gas reserves in 2002 and the limited amount of reserves on properties we currently own interests in, we expect that our future revenues will be primarily dependent on the level of use of our pipeline systems. Revenues from oil and gas sales accounted for approximately 55% of our total revenues in 2006. However, only 17% of our revenues were from oil and gas sales in 2007. Total revenues in 2007 decreased by approximately $1.3 million from 2006. Various factors will 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 these interests will decrease. The rate of production from High Island Block 37 declined by approximately 78% in 2007. Production from High Island Block A-7 ceased during 2007. Production data from High Island Block A-7 has provided evidence that the well may have reached the end of its production life. We believe that production from the producing High Island Block 37 well could continue until mid 2008. However, the well could deplete faster than anticipated or could develop production problems resulting in the cessation of production. Since the High Island Block 115 well recently commenced production, it is not possible to accurately predict at what rate or for how long this well will continue to produce. Unless we are able to replace this 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.

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.

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.

We have historically needed substantial amounts of cash to fund our working capital requirements. We have experienced a negative working capital position in past years and have been dependent on debt and equity financing and sales of revenue generating assets to meet our working capital requirements that were not funded from operations. Low commodity prices, production problems, declines in production, disappointing drilling results and other factors beyond our control could further reduce our funds from operations. As a result we may have to seek debt and equity financing to meet our working capital requirements. Furthermore, we incurred a loss of approximately $1.6 million this year and have incurred losses in the past. These losses may affect our ability to obtain financing. In addition, financing may not be available to us in the future on acceptable terms or at all. In the event additional capital is not available, we may be forced to sell some of our assets on unfavorable terms or on an untimely basis.

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.

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 higher, but 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.

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.

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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 prices and costs in effect at December 31, 2007. 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.

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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.

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.

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

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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.

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 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.

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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.
Nonoperating 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. 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.

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Proved Developed Non-producing. Reserves sub-categorized as non-producing include shut-in and behind pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in awaiting pipeline connections or as a result of a market interruption, or (3) 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 major 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 2. Description of Property

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 $107,000.

Item 3. Legal Proceedings

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

Item 4. Submission of Matters to a Vote of Security Holders

None.

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PART II

Item 5. Market for Common Equity, Related Stockholder Matters and Small Business Issuer Purchases of Equity Securities

Market Price for Common Stock

Our common stock is quoted on the NASDAQ Capital Market under the ticker symbol BDCO . As of March 24, 2008, there were approximately 500 stockholders of record and we estimate that there are more than 1,000 beneficial owners of our common stock. NASDAQ quotations reflect inter-dealer prices, without adjustment for retail mark-ups, markdowns or commissions and may not represent actual transactions. The following table sets forth, for the periods indicated, the high and low closing bid price for our common stock as reported by the NASDAQ.

Quarter Ended	High	Low
March 31, 2006	$ 3.32	$ 1.91
June 30, 2006	$ 8.00	$ 3.45
September 30, 2006	$ 6.14	$ 3.65
December 31, 2006	$ 4.34	$ 2.91
March 31, 2007	$ 4.33	$ 2.81
June 30, 2007	$ 4.01	$ 2.97
September 30, 2007	$ 3.80	$ 2.92
December 31, 2007	$ 3.15	$ 1.21

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.

Item 6. 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 Description of Business and Item 7 Notes to Consolidated Financial Statements.

Executive Summary

We are engaged in two lines of business: (i) provision of 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, we also continue to review and evaluate opportunities to further develop our existing oil and gas properties and acquire additional oil and gas properties.

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During 2007, we have benefited from an increase in revenues from our pipeline operations resulting from the commencement of deliveries of production from shippers on both the Blue Dolphin System and the GA 350 Pipeline during 2006 and 2007. The level of throughput on the Blue Dolphin System has increased due to the addition of three shippers during 2006 and one shipper in July 2007. The shipper that commenced deliveries in 2007 represented production from two wells. The Blue Dolphin System is currently transporting an aggregate of approximately 26 MMcf of gas per day from ten shippers.

The GA 350 Pipeline throughput has also increased from the addition of one shipper in 2006 and two shippers in 2007. The GA 350 Pipeline is currently transporting an aggregate of approximately 29 MMcf of gas per day from six shippers.

Production and resulting revenues from our interests in wells in the High Island area have declined as reserves have been depleted. High Island Block 37 is currently producing approximately 3 MMcf of gas per day from one well. Further development of reserves in the block is currently being evaluated.

The High Island Block A-7 well experienced production difficulties during the second quarter of 2007 and is currently shut in. Production data had previously indicated that the well was nearing the end of its productive life and this point may now have been reached.

During the second quarter, a well in High Island Block 115 in which we had previously earned a 2.5% working interest was re-entered and sidetracked successfully. Production from this well commenced in late-November 2007 and is currently producing approximately 9 MMcf of gas per day.

Despite the recent throughput gains, our pipeline assets remain significantly under-utilized. The Blue Dolphin System is currently operating at approximately 15% of capacity, the GA 350 Pipeline is currently operating at approximately 45% of capacity and the Omega Pipeline is inactive. Production declines, temporary stoppages or cessations of production from wells tied into our pipelines or from our working interests in the High Island area wells noted above 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.

Liquidity and Capital Resources

During 2007, our working capital position decreased approximately $1.1 million. At December 31, 2007, we had working capital of approximately $5.6 million compared to approximately $6.7 million at the end of 2006. Working capital increased during 2006 primarily due to net proceeds of $3.8 million received from two private placements in March and April of 2006, revenues from oil and gas sales and increased revenues from our pipeline operations. Working capital at the end of 2007 was negatively affected by significantly reduced revenues from sales of oil and gas, partially offset by increased revenues from our pipeline operations.

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The following table summarizes our financial position for the years indicated (in thousands):

	Years Ended December 31,			
	2007		2006	
	Amount	%	Amount	%
Working capital	$ 5,598	55%	$ 6,652	57
Property and equipment, net	4,504	45%	4,912	43
Other noncurrent assets	11		22	
Total	$ 10,113	100%	$ 11,586	100
Long-term liabilities	$ 1,883	19%	$ 2,014	17
Stockholders equity	8,230	81%	9,572	83
Total	$ 10,113	100%	$ 11,586	100

Our financial condition continues to be adversely affected by the low utilization of our pipeline assets. The average rates of throughput on the Blue Dolphin System and the GA 350 Pipeline during 2007 were significantly higher than 2006, however, the level of utilization of these pipelines is significantly below maximum capacity. The Blue Dolphin System transported an average of 22.3 MMcf of gas per day during 2007 as compared to 17.3 MMcf of gas per day during 2006. The GA 350 Pipeline transported an average of 22.6 MMcf of gas per day during 2007 as compared to 9.1 MMcf of gas per day during 2006. The Blue Dolphin System and the GA 350 Pipeline each transported approximately 8.2 Bcf of gas during 2007. In 2006, the Blue Dolphin System transported approximately 6.3 Bcf of gas and the GA 350 Pipeline transported approximately 3.3 Bcf of gas. Despite the increase in transportation volumes, the Blue Dolphin System is currently operating at approximately 15% of capacity and the GA 350 Pipeline is currently operating at approximately 45% of capacity.

Throughput on the Blue Dolphin System and the GA 350 Pipeline increased significantly during 2006 and 2007 as a result of production from seven shippers commencing deliveries from eight wells. Four of these shippers are delivering production into the Blue Dolphin System and three of the shippers are delivering production into the GA 350 Pipeline. In 2006, one shipper began deliveries into the Blue Dolphin System in each of May, June and November, and in July 2007, a shipper began deliveries from two wells. On the GA 350 Pipeline, shippers began deliveries in December 2006, and in June and September of 2007.

In addition to the throughput gains from shippers added to the pipelines in 2006 and 2007, the Blue Dolphin System also benefited from the drilling activities of certain existing shippers. In July 2006, an existing shipper successfully recompleted a well, resulting in an increase of daily production from that well, and in June 2007, another existing shipper drilled a new well, also resulting in an increase in daily production. Annual revenues from pipeline operations increased to $2,494,406 in 2007 as compared to $1,939,894 in 2006.

Ultimately, the future utilization of our pipelines and related facilities will depend upon the success of drilling programs around our pipelines, as well as attraction and retention of producer/shippers to the pipeline systems. We believe that the pipelines are in geographic market areas that are of interest to oil and gas operators. This assessment is based on leasing activity and information obtained directly from the operators of properties near our pipelines. If we are successful in our efforts to attract additional shippers to our pipelines, we would gain additional throughput, resulting in additional revenues. Additional throughput will be required to offset the natural decline in throughput from existing wells as reserves are depleted.

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The revenues from our working interest in High Island Block 37 have declined as the rate of production declines as expected as reserves are depleted. High Island Block 37 averaged approximately 5.4 MMcf of gas per day in 2007 as compared to approximately 15.6 MMcf of gas per day in 2006. We recognized gross oil and gas sales revenues of approximately $276,000 and $890,000 for the twelve months ended December 31, 2007 and 2006, respectively, associated with our approximate 2.8% working interest in High Island Block 37. The A-2 well experienced production problems in April 2007 and was shut in for approximately eight months. Production from this well was re-started in December 2007. The B-1 well went off production during January 2008, and production from that well has not been re-established. The A-2 well is currently producing at a rate of approximately 3 MMcf of gas per day. We believe that the A-2 well could continue to produce until mid-2008, however, the well could deplete faster than currently anticipated or could develop production problems resulting in the cessation of production. Further development of reserves in the block is currently being evaluated.

The High Island Block A-7 well also experienced production problems in the second quarter 2007. The well has produced only intermittently since. It is currently shut in and may have reached the end of its productive life. The well averaged approximately 0.7 MMcf of gas per day in 2007 as compared to approximately 5.6 MMcf of gas per day in 2006. We recognized gross oil and gas sales revenues of approximately $211,000 and $1,469,000 for the twelve months ended December 31, 2007 and 2006, respectively, associated with our approximate 8.9% working interest in the High Island Block A-7 well.

During the second quarter, a well in High Island Block 115 which we had previously earned a 2.5% working interest was re-entered and sidetracked successfully. The well commenced production in late November 2007 and produced at an average rate of approximately 6.3 MMcf of gas per day during the remainder of 2007. We recognized gross oil and gas sales revenues of approximately $30,000 from this well in 2007. The well is currently producing at a rate of approximately 9MMcf of gas per day. Due to the low utilization rate of our pipeline assets, without the revenues and resulting cash inflows we receive from oil and gas sales, we may not be able to generate sufficient cash from operations to cover our operating and general and administrative expenses.

The following table summarizes certain of our contractual obligations and other commercial commitments at December 31, 2007 (in thousands):

CONTRACTUAL OBLIGATIONS AND OTHER COMMERCIAL COMMITMENTS

	Payments Due by Period				
	Total	1 Year or Less	1-3 Years	3-5 Years	5 Years or More
Operating leases	$ 383	$ 103	$ 280	$	$
Employment agreement	408	175	233		
Asset retirement obligations	2,094	262	89	35	1,708
Other long-term liabilities	78	26	52		
Total contractual obligations and other commercial commitments	$ 2,963	$ 566	$ 654	$ 35	$ 1,708

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Results of Operations

For the year ended December 31, 2007 (current period), we reported a net loss of $1,625,572, compared to net income of $912,864 for the year ended December 31, 2006 (previous period).

2007 Compared to 2006

Revenue from Pipeline Operations. Revenues from pipeline operations increased by $554,512, or 29%, in the current period to $2,494,406. Revenues in the current period from the Blue Dolphin System totaled approximately $2,107,000 compared to approximately $1,755,000 in the previous period primarily as a result of additional throughput from three new shippers in 2006, one new shipper in 2007 and a new well drilled by an existing shipper in 2007. Daily gas volumes transported through the Blue Dolphin System averaged approximately 22 MMcf of gas per day in the current period compared to approximately 17 MMcf of gas per day in the previous period. Revenues on the GA 350 Pipeline increased by approximately $202,000 to approximately $387,000 in the current period primarily due to throughput from new shippers. Average daily gas volumes transported increased to approximately 23 MMcf of gas per day in the current period from approximately 9 MMcf of gas per day in the previous period.

Revenue from Oil and Gas Sales. Revenues from oil and gas sales decreased by $1,841,403, or 78%, to $517,411 in the current period primarily due to decreased levels of production from our non-operated interests in High Island Blocks 37 and A-7. High Island Block A-7 ceased production in the current period and one well at High Island Block 37 was shut-in, leaving one producing well, for a portion of the current period. This decrease in production was partially offset by the commencement of production at High Island Block 115 in late November of the current period. Revenues were also negatively affected by a decrease in the realized price of natural gas. Our average realized gas price per Mcf in the current period was $6.54 compared to $6.83 in the previous period. The sales mix by product was 92% gas and 8% condensate and natural gas liquids. Our average realized price per barrel of condensate was $58.45 in the current period compared to $62.60 in the previous period. Revenue breakdown for the current period by field was approximately $211,000 for High Island Block A-7, $276,000 for High Island Block 37 and $30,000 for High Island Block 115.

Pipeline Operating Expenses. Pipeline operating expenses increased by $661,749 to $1,788,288 in the current period. This increase was due primarily to costs of approximately $154,000 to repair a pipeline leak in January 2007, approximately $159,000 to repair the offshore compressor on Platform C in Galveston Area Block 288, approximately $55,000 for painting and repairs to the office, buildings and barge dock at the Freeport facility, increased insurance costs of approximately $207,000 due to higher renewal rates and increased legal fees of approximately $22,000. The legal fees are primarily associated with an action filed against us, the outcome of which we do not believe will have a material impact.

Lease Operating Expenses. Lease operating expenses decreased $216,995 in the current period to $240,317 primarily due to the cessation of production at High Island Block A-7.

Depletion, Depreciation and Amortization. Depletion, depreciation and amortization expense increased by $52,646 in the current period to $554,704. Depreciation associated with estimated dismantlement costs increased by approximately $64,000 due to an increase in asset retirement obligations.

General and Administrative Expenses. General and administrative expenses increased $405,174 in the current period to $2,178,276 primarily due to increased employee-related expenses of approximately $497,000 associated with a staff addition, salary increases, bonuses, 401(k) matching, increased employee health benefits expense and non-cash compensation expense associated with 2007 stock option grants. Accounting-related expenses increased approximately $67,000 primarily due to Sarbanes-Oxley compliance work. These increases were partially offset by decreased legal fees of approximately $57,000 and consulting fees of approximately $142,000.

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Interest and Other Expense. Interest and other expense decreased $42,224 in the current period to $0 due to the elimination of our outstanding debt in the previous period.

Interest and Other Income. Interest and other income increased $110,978 in the current period due to an increase in invested funds and the interest rate earned on those funds.

Gain on Extinguishment of Debt. In 2006, we recognized a gain of $500,000 on the extinguishment of the contingent portion of the promissory note payable to MCNIC. The contingent portion of the note was extinguished effective December 31, 2006.

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 developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules at or before their adoption, and believe the proper implementation and consistent application of accounting rules is critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by comparatively analyzing similar situations and reviewing the accounting guidance governing them, and may consult with our independent accountants 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 of December 31, 2007 and the accounting for future asset retirement costs.

In accordance with SFAS No. 144, *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, 2007. Accordingly, we developed future cash flows as of December 31, 2007 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, 2007.

The accounting for future abandonment costs changed on January 1, 2003 with the adoption of SFAS No. 143. This new standard 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

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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.

We adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-An Interpretation of FASB Statement No. 109* (FIN 48), effective January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes* (SFAS 109). FIN 48 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 new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

The evaluation of a tax position in accordance with FIN 48 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 FIN 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year.

The provisions of FIN 48 have been applied to all of our material tax positions taken from January 1, 2007 through the fiscal year ended December 31, 2007. 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 FIN 48. 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.

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Recently Issued Accounting Pronouncements and Accounting Developments

In February 2007, the Financial Accounting Standards Board (the FASB) issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to FASB Statement No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, applies to all entities with available-for-sale and trading securities. The FASB s stated objective in issuing this standard is as follows: to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions.

The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings (or another performance indicator if the business entity does not report earnings) at each subsequent reporting date. The fair value option: (i) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (ii) is irrevocable (unless a new election date occurs); and (iii) is applied only to instruments and not to portions of instruments.

SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes that choice in the first 120 days of that fiscal year and also elects to apply the provisions of FASB Statement No. 157, *Fair Value Measurements* (SFAS 157). We do not expect the adoption of SFAS 159 to have a material effect on our financial statements.

In September 2006, SFAS 157 was issued by the FASB. This new standard provides guidance for using fair value to measure assets and liabilities. The FASB believes the standard also responds to investors requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value and the effect of fair value measurements on earnings. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances.

Currently, over 40 accounting standards within GAAP require (or permit) entities to measure assets and liabilities at fair value. Prior to SFAS 157, the methods for measuring fair value were diverse and inconsistent, especially for items that are not actively traded. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-model value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data.

Under SFAS 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. In this standard, FASB clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy.

The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any

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financial statements for an interim period within that fiscal year. We do not expect the adoption of SFAS 157 to have a material effect on our financial statements.

In December 2007, the FASB issued SFAS No. 141R, *Business Combinations* (SFAS 141R), which replaces SFAS No. 141, *Business Combinations*. SFAS 141R establishes principles and requirements for determining how an enterprise recognizes and measures the fair value of certain assets and liabilities acquired in a business combination, including non-controlling interests, contingent consideration, and certain acquired contingencies. SFAS 141R also requires acquisition-related transaction expenses and restructuring costs be expensed as incurred rather than capitalized as a component of the business combination. SFAS 141R will be applicable prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS 141R would have an impact on accounting for any businesses acquired after the effective date of this pronouncement.

In December 2007, the FASB also issued SFAS No. 160, *Non-controlling Interests in Consolidated Financial Statements An Amendment of ARB No. 51* (SFAS 160). SFAS 160 establishes accounting and reporting standards for the non-controlling interest in a subsidiary (previously referred to as minority interests). SFAS 160 also requires that a retained non-controlling interest upon the deconsolidation of a subsidiary be initially measured at its fair value. Upon adoption of SFAS 160, we would be required to report any non-controlling interests as a separate component of stockholders equity. We would also be required to present any net income allocable to non-controlling interests and net income attributable to the stockholders of the company separately in our consolidated statements of income. SFAS 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 shall be applied prospectively. SFAS 160 would have an impact on the presentation and disclosure of the non-controlling interests of any non wholly-owned businesses acquired in the future.

Item 7. 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 sheet of Blue Dolphin Energy Company and Subsidiaries (the Company) as of December 31, 2007, 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, 2007. 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 audit to obtain reasonable assurance about whether the 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, 2007, and the consolidated results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note (1) to the consolidated financial statements, effective January 1, 2007, the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109.*

/s/ UHY LLP
Houston, Texas
March 31, 2008

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Balance Sheet

		December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$	5,226,779
Accounts receivable		693,977
Prepaid expenses and other current assets		508,517
Total current assets		6,429,273
Property and equipment		
Oil and gas properties (full-cost method)		751,175
Pipelines		4,659,686
Onshore separation and handling facilities		1,919,402
Land		860,275
Other property and equipment		279,468
		8,470,006
Less:		
Accumulated depletion, depreciation and amortization		3,966,087
Net property and equipment		4,503,919
Other assets		10,640
TOTAL ASSETS	$	10,943,832
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$	432,974
Accrued expenses and other current liabilities		109,628
Current portion of asset retirement obligations		262,187
Current portion of other long-term liabilities		25,996
Total current liabilities		830,785
Long-term liabilities:		
Asset retirement obligations, net of current portion		1,831,520
Other long-term liabilities, net of current portion		51,992
Total long-term liabilities		1,883,512

TOTAL LIABILITIES		2,714,297
Commitments and contingencies		
Stockholders equity:		
Common stock, $.01 par value, 25,000,000 shares authorized, 11,610,363 shares issued and outstanding		116,104
Additional paid-in capital		32,117,950
Accumulated deficit		(24,004,519)
Total stockholder s equity		8,229,535
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	10,943,832

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Statements of Operations

	Years Ended December 31, 2007	2006
Revenue from operations:		
Pipeline operations	$ 2,494,406	$ 1,939,894
Oil and gas sales	517,411	2,358,814
Total revenue from operations	3,011,817	4,298,708
Cost of operations:		
Pipeline operating expenses	1,788,288	1,126,539
Lease operating expenses	240,317	457,312
Depletion, depreciation and amortization	554,704	502,058
General and administrative expenses	2,178,276	1,773,102
Accretion expense	120,384	107,589
Total cost of operations	4,881,969	3,966,600
Income (loss) from operations	(1,870,152)	332,108
Other income (expense):		
Interest and other expense		(42,224)
Interest and other income	248,637	137,659
Gain on extinguishment of debt		500,000
Total other income (expense)	248,637	595,435
Income (loss) before income taxes	(1,621,515)	927,543
Income tax expense	(4,057)	(14,679)
Net income (loss)	$ (1,625,572)	$ 912,864
Income (loss) per common share:		
Basic	$ (0.14)	$ 0.08
Diluted	$ (0.14)	$ 0.08
Weighted average number of common shares outstanding:		
Basic	11,568,311	11,202,951
Diluted	11,568,311	11,306,662

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, 2005	9,939,302	$ 99,393	$ 27,980,475	$ (23,291,811)	$ 4,788,057
Sale of common stock	1,571,432	15,714	3,825,110		3,840,824
Common stock issued for services	39,960	400	29,600		30,000
Exercise of warrants	4,758	48	(48)		
Net income				912,864	912,864
Balance at December 31, 2006	11,555,452	115,555	31,835,137	(22,378,947)	9,571,745
Issuance under stock plans	27,938	279	22,071		22,350
Common stock issued for services	26,973	270	78,890		79,160
Stock-based compensation			181,852		181,852
Net loss				(1,625,572)	(1,625,572)
Balance at December 31, 2007	11,610,363	$ 116,104	$ 32,117,950	$ (24,004,519)	$ 8,229,535

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, 2007	2006
OPERATING ACTIVITIES		
Net income (loss)	$ (1,625,572)	$ 912,864
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depletion, depreciation and amortization	554,704	502,058
Accretion expense	120,384	107,589
Gain on extinguishment of debt		(500,000)
Stock-based compensation	181,852	
Common stock issued for services	79,160	30,000
Changes in operating assets and liabilities:		
Accounts receivable	480,342	427,977
Prepaid expenses and other current assets	(159,991)	(164,053)
Abandonment costs incurred	(76,290)	
Accounts payable, accrued expenses and other liabilities	262,245	(100,876)
Net cash provided by (used in) operating activities	(183,166)	1,215,559
INVESTING ACTIVITIES		
Exploration and development costs		(15,700)
Capital expenditures	(111,552)	(267,447)
Investment in unconsolidated affiliates		(1,177)
Net cash used in investing activities	(111,552)	(284,324)
FINANCING ACTIVITIES		
Proceeds from the sale of common stock, net of offering costs		3,840,824
Payments on borrowings		(570,000)
Proceeds from exercise of stock options	22,350	
Net cash provided by financing activities	22,350	3,270,824
Increase (decrease) in cash and cash equivalents	(272,368)	4,202,059
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	5,499,147	1,297,088
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 5,226,779	$ 5,499,147
Supplementary cash flow information:		
Interest paid	$	$ 88,334

Non-cash activities:				
Change in estimate for asset retirement obligations and related fixed assets	$	35,205	$	

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 the estimated useful life of pipeline assets, valuation of stock-based payments and reserve information, which affects the depletion calculation as well as the full cost ceiling limitation. While we believe current estimates are reasonable and appropriate, actual results could differ from those estimated.

Cash Equivalents

Cash equivalents include liquid investments with an original maturity of three months or less. 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.

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. 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.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Continued)

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 Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-lived Assets*, assets are grouped and evaluated for impairment based on the ability to identify separate cash flows generated therefrom.

Other Property and Equipment

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

Asset Retirement Obligations

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, as amended, 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.

SFAS No. 143 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, 2007 and 2006 (in thousands).

	Years Ended December 31,	
	2007	2006
Beginning asset retirement obligations	$ 2,014	$ 1,756
Liabilities incurred	36	
Liabilities settled	(76)	
Accretion expense	120	108
Revisions in estimated cash flows		150
Ending asset retirement obligations	$ 2,094	$ 2,014

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
Stock-Based Compensation
Effective January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (Revised), *Share-Based Payments* (SFAS 123(R)) utilizing the modified prospective approach. Prior to the adoption of SFAS 123(R) we accounted for stock option grants in accordance with APB Opinion No. 25, *Accounting for Stock Issued to Employees* (the intrinsic value method), and accordingly, recognized no compensation expense when stock options were granted with an exercise price equal to the grant date fair market value of a share of our common stock.
Under the modified prospective approach, SFAS 123(R) applies to new awards and to awards that were outstanding on January 1, 2006 that are subsequently modified, repurchased, or cancelled. Under the modified prospective approach, had there been any awards granted during 2006, compensation expense recognized in the period would have included compensation cost for all share-based payments granted prior to, but not yet vested, based on the grant date fair value estimated in accordance with the original provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation*, and compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). Prior periods were not restated to reflect the impact of adopting the new standard.
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, 2007 was not material.
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.
Income Taxes
We provide for income taxes using the asset and liability method pursuant to SFAS No. 109, *Accounting for Income Taxes* and FIN 48. Under the asset and liability method of SFAS No. 109, 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 carryforwards. 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. Under FIN 48, which we adopted effective January 1, 2007, tax positions are evaluated 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.

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

We apply the provisions of Statement of Financial Accounting Standards No. 128, *Earnings per Share* (SFAS 128). SFAS 128 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. SFAS 128 requires dual presentation of basic EPS and diluted EPS on the face of the income statement 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 twelve months ended December 31, 2007, because their assumed exercise and conversion would have an antidilutive effect on the computation of diluted loss per share.

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

	Net Income (Loss)	Weighted-Average Number of Common Shares Outstanding and Potential Dilutive Common Shares	Per Share Amount
Year ended December 31, 2007:			
Basic and diluted	$ (1,625,572)	11,568,311	$ (0.14)
Year ended December 31, 2006:			
Basic	$ 912,864	11,202,951	$ 0.08
Effect of dilutive stock options		103,711	
Diluted	$ 912,864	11,306,662	$ 0.08

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
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Recently Issued Accounting Pronouncements

In February 2007, the Financial Accounting Standards Board (the FASB) issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to FASB Statement No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, applies to all entities with available-for-sale and trading securities. The FASB s stated objective in issuing this standard is as follows: to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions.

The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings (or another performance indicator if the business entity does not report earnings) at each subsequent reporting date. The fair value option: (i) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (ii) is irrevocable (unless a new election date occurs); and (iii) is applied only to instruments and not to portions of instruments.

SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes that choice in the first 120 days of that fiscal year and also elects to apply the provisions of FASB Statement No. 157, *Fair Value Measurements* (SFAS 157). We do not expect the adoption of SFAS 159 to have a material effect on our financial statements.

In September 2006, SFAS 157 was issued by the FASB. This new standard provides guidance for using fair value to measure assets and liabilities. The FASB believes the standard also responds to investors requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value and the effect of fair value measurements on earnings. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances.

Currently, over 40 accounting standards within GAAP require (or permit) entities to measure assets and liabilities at fair value. Prior to SFAS 157, the methods for measuring fair value were diverse and inconsistent, especially for items that are not actively traded. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-market value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data.

Under SFAS 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. In this standard, FASB clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy.

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

The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We do not expect the adoption of SFAS 157 to have a material effect on our financial statements.

In December 2007, the FASB issued SFAS No. 141R, *Business Combinations* (SFAS 141R), which replaces SFAS No. 141, *Business Combinations*. SFAS 141R establishes principles and requirements for determining how an enterprise recognizes and measures the fair value of certain assets and liabilities acquired in a business combination, including non-controlling interests, contingent consideration, and certain acquired contingencies. SFAS 141R also requires acquisition-related transaction expenses and restructuring costs be expensed as incurred rather than capitalized as a component of the business combination. SFAS 141R will be applicable prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS 141R would have an impact on accounting for any businesses acquired after the effective date of this pronouncement.

In December 2007, the FASB also issued SFAS No. 160, *Non-controlling Interests in Consolidated Financial Statements An Amendment of ARB No. 51* (SFAS 160). SFAS 160 establishes accounting and reporting standards for the non-controlling interest in a subsidiary (previously referred to as minority interests). SFAS 160 also requires that a retained non-controlling interest upon the deconsolidation of a subsidiary be initially measured at its fair value. Upon adoption of SFAS 160, we would be required to report any non-controlling interests as a separate component of stockholders equity. We would also be required to present any net income allocable to non-controlling interests and net income attributable to the stockholders of the company separately in our consolidated statements of income. SFAS 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 shall be applied prospectively. SFAS 160 would have an impact on the presentation and disclosure of the non-controlling interests of any non wholly-owned businesses acquired in the future.

(2) Liquidity

During 2007, our working capital position decreased approximately $1.1 million to $5.6 million compared to $6.7 million at the end of 2006. Working capital at the end of 2007 reflects the impact of significantly reduced revenues from sales of oil and gas, partially offset by increased revenues from our pipeline operations. Due to the low utilization of our pipeline assets, without the revenues and resulting cash inflows we receive from oil and gas sales, we may not be able to generate sufficient cash from operations to cover our operating and general and administrative expenses.

The Blue Dolphin System is currently transporting an aggregate of approximately 26 MMcf of gas per day from ten shippers and the GA 350 Pipeline is currently transporting an aggregate of approximately 29 MMcf of gas per day from six shippers. Throughput on the Blue Dolphin System and the GA 350 Pipeline increased significantly during 2006 and 2007 as a result of production from seven shippers commencing deliveries from eight wells. Four of these shippers are delivering production into the Blue Dolphin System and three of the shippers are delivering production into the GA 350 Pipeline. In 2006, one shipper began deliveries into the Blue Dolphin System in each of May, June and November, and in 2007, a shipper began deliveries from two wells in July. On the GA 350 Pipeline, shippers began deliveries in December 2006, and in June and September of 2007.

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

In addition to the throughput gains from shippers added to the pipelines, the Blue Dolphin System also benefited from the drilling activities of certain existing shippers. In July 2006, an existing shipper successfully recompleted a well, resulting in an increase of daily production from that well, and in June 2007, another existing shipper drilled a new well, also resulting in an increase in daily production. Annual revenues from pipeline operations increased to $2,494,406 in 2007 as compared to $1,939,894 in 2006.

The revenues from our working interest in High Island Block 37 have declined as the rate of production declines as expected as reserves are depleted. High Island Block 37 averaged approximately 5.4 MMcf of gas per day in 2007 as compared to approximately 15.6 MMcf of gas per day in 2006. We recognized gross oil and gas sales revenues of approximately $276,000 and $890,000 for the twelve months ended December 31, 2007 and 2006, respectively, associated with our approximate 2.8% working interest in High Island Block 37. The A-2 well experienced production problems in April 2007 and was shut in for approximately eight months. The well came back on production in December 2007. The B-1 well shut in during January 2008, and production from that well has not yet been re-established. The A-2 well is currently producing at a rate of approximately 3 MMcf of gas per day. We believe that the A-2 well could continue to produce until mid-2008, however, the well could deplete faster than currently anticipated or could develop production problems resulting in the cessation of production. Further development of reserves in the block is currently being evaluated.

The High Island Block A-7 well also experienced production problems in the second quarter 2007. The well has produced only intermittently since. It is currently shut in and may have reached the end of its productive life. The well averaged approximately 0.7 MMcf of gas per day in 2007 as compared to approximately 5.6 MMcf of gas per day in 2006. We recognized gross oil and gas sales revenues of approximately $211,000 and $1,469,000 for the twelve months ended December 31, 2007 and 2006, respectively, associated with our approximate 8.9% working interest in the High Island Block A-7 well.

During the second quarter, a well in High Island Block 115 which we had previously earned a 2.5% working interest was re-entered and sidetracked successfully. The well commenced production in late November 2007 and produced at an average rate of approximately 6.3 MMcf of gas per day during the remainder of 2007. We recognized gross oil and gas sales revenues of approximately $30,000 from this well in 2007. The well is currently producing at a rate of approximately 9 MMcf of gas per day.

(3) 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.

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

(4) Income Taxes

Income tax expense consisted of $4,057 of state income tax for 2007, and $14,679 of federal income tax expense for 2006.

The income tax effects of temporary differences that give rise to significant portions of deferred tax assets and deferred tax liabilities at December 31, 2007 are presented below:

Deferred tax assets:	
Net operating loss and capital loss carryforwards	$ 5,700,789
AMT credit carryforward	11,564
Basis differences in property and equipment	151,268
Total deferred tax assets	5,863,981
Less: valuation allowance	(5,863,981)
Deferred tax assets, net	$

In assessing the recoverability of deferred tax assets, we apply SFAS No. 109 and FIN 48, which we adopted effective January 1, 2007, to 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, 2007 due to our uncertainty as to the utilization of the deferred tax assets in the foreseeable future.

Our effective tax rate applicable to continuing operations in 2007 and 2006 is as follows:

	Years Ended December 31,	
	2007	2006
Expected tax rate	(34.00%)	34.00%
Change in valuation allowance recognized in earnings	34.25%	(32.42%)
	0.25%	1.58%

For federal tax purposes, we have net operating loss carryforwards (NOLs) of approximately $16.8 million at December 31, 2007. These NOLs must be utilized prior to their expiration, which is between 2011 and 2027.

We adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-An Interpretation of FASB Statement No. 109* (FIN 48), effective January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes* (SFAS 109). FIN 48 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 new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

The evaluation of a tax position in accordance with FIN 48 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

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

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 FIN 48 have been applied to all of our material tax positions taken through the date of adoption and through the fiscal year ended December 31, 2007. 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 FIN 48. 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. The new legislation s effective date is January 1, 2008, which means that our first Texas margins tax (TMT) return will not become due until May 15, 2008 and will be based on our 2007 operations. Although the 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 guidance provided in SFAS 109, we have properly determined the impact of the newly-enacted legislation in the determination of our reported state current and deferred income tax liability.

(5) Long-Term Debt

Under the terms of the original Purchase Agreement, we acquired MCNIC s one-third interests in both the Blue Dolphin System and the inactive Omega Pipeline. On February 28, 2005 (effective as of January 1, 2005), we entered into the Amendment to our Purchase Agreement with MCNIC. Pursuant to the terms of the Amendment, the Original Promissory Note was exchanged for the New Promissory Note. In addition to the New Promissory Note, MCNIC could receive additional payments of up to $500,000 from 50% of the net profits, if any, realized from the one-third interest in the Blue Dolphin System through December 31, 2006. We made a principal payment on the New Promissory Note of $30,000 upon the execution of the Amendment and under the terms of the New Promissory Note we made monthly principal payments of $10,000 through its maturity date of December 31, 2006. The principal amount of the New Promissory Note also could have been increased by up to $500,000 if 50% or more of our 83% interest in the Blue Dolphin System was sold before December 31, 2006. We were not required to make any contingent payments on the New Promissory Note and extinguished the $500,000 contingent portion of the New Promissory Note effective December 31, 2006.

In April 2005, the holders of $450,000 of the $750,000 aggregate principal amount of promissory notes sold in September 2004, agreed to extend the maturity date of their promissory notes to June 30, 2006, and to defer the payment of all unpaid and future interest on their promissory notes until maturity. The promissory notes were originally sold on September 8, 2004 pursuant to the Note and Warrant Purchase Agreement we entered into with certain accredited investors and certain of our directors. The $300,000 aggregate principal amount of promissory notes was retired at maturity in 2005. The remaining $450,000 aggregate principal amount of promissory notes was retired on June 30, 2006.

Total interest expense was approximately $0 and $32,000 for 2007 and 2006, respectively.

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

(6) Exercise of Warrants

On December 21, 2006, 4,286 outstanding warrants were exercised by warrant holders. The exercises were accomplished via a net exercise, whereby holders surrender their right to receive a portion of the shares of common stock. The rights to receive 2,618 shares of common stock were surrendered and we issued 1,668 shares of common stock upon exercise. The Company did not receive any proceeds from the net exercise of these warrants.

On August 8, 2006, 11,417 outstanding warrants were exercised by warrant holders. The exercises were also accomplished via a net exercise, whereby holders surrender their right to receive a portion of the shares of common stock. The rights to receive 8,622 shares of common stock were surrendered and we issued 2,795 shares of common stock upon exercise. The Company did not receive any proceeds from the net exercise of these warrants.

On April 17, 2006, 429 outstanding warrants were exercised by warrant holders. The exercises were again accomplished via a net exercise, whereby holders surrendered their right to receive a portion of the shares of common stock. The rights to receive 134 shares of common stock were surrendered and the Company issued 295 shares of common stock upon exercise.

These securities were issued in reliance upon the exemption from registration pursuant to Section 4(2) under the Securities Act of 1933, as amended.

A summary of warrant activity for 2007 and 2006 is as follows:

	Number of Warrants	Weighted-Average Exercise Price	Warrants Exercisable	Weighted-Average Exercise Price
Outstanding, December 31, 2005				
Granted	32,572	$4.48		
Exercised	(16,132)	$3.55		
Outstanding, December 31, 2006	16,440	$5.39	16,440	$5.39
Granted		$0.00		
Exercised		$0.00		
Outstanding, December 31, 2007	16,440	$5.88	16,440	$5.88

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

At December 31, 2007, the range of warrant prices for shares under warrants and the weighted-average remaining contractual life was as follows:

	Warrants Outstanding, Fully Vested and Exercisable at December 31, 2007		
Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price
$5.50 to $6.00	16,440	1.2	$ 5.88

(7) Stockholders Equity

In March 2006, we entered into a stock purchase agreement with certain accredited investors for the private placement of 1,171,432 shares of our common stock. Net proceeds from the offering after payment of commissions and expenses were approximately $2.0 million. In April 2006, we entered into a second stock purchase agreement with an accredited institutional investor for the private placement of 400,000 shares of our common stock. Net proceeds from the offering after payment of commissions and expenses were approximately $1.8 million. Warrants to purchase 32,572 shares of common stock were issued associated with these offerings and 16,132 of the warrants were exercised in 2006 via net exercise resulting in the issuance of 4,758 shares of common stock.

In January 2006, we issued 30,000 shares of common stock into our Blue Dolphin Services Co. 401(k) Plan as a 2005 contribution.

(8) 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 from 650,000 shares to 1,200,000 shares after approval by our stockholders at the 2007 Annual Meeting of Stockholders, which was held on May 30, 2007. As of December 31, 2007, we had 274,040 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 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.

SFAS 123(R) states that 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

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

for the foreseeable future will be applied to the valuation allowance in determining our net operating loss carryforward.

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 Staff Position FAS123(R)-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*.

Pursuant to SFAS 123(R), 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 year ended December 31, 2007. There were no stock options granted during the year ended December 31, 2006.

	Years Ended December 31,	
	2007	2006
Stock options granted	378,500	0
Risk-free interest rate	4.31 to 4.80%	N/A
Expected term, in years	3.75 to 5.97	N/A
Expected volatility	81.67 to 92.4%	N/A
Dividend yield	0.00%	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 two years ago. These changes include the improvement in our working capital, improved 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 Securities and Exchange Commission 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, 2007, there were a total of 491,559 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, 2007			
	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Options outstanding at December 31, 2005	143,997	$ 1.56		
Options granted		$ 0.00		
Options exercised		$ 0.00		
Options expired or cancelled		$ 0.00		
Options outstanding at December 31, 2006	143,997	$ 1.56		
Options granted	378,500	$ 2.93		
Options exercised	(27,938)	$ 0.80		
Options expired or cancelled	(3,000)	$ 6.00		
Options outstanding at December 31, 2007	491,559	$ 2.61	7.2	$ 79,674
Options exercisable at December 31, 2007	141,559	$ 1.86	5.6	$ 79,674

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

The following table summarizes additional information about stock options outstanding at December 31, 2007:

	Options Outstanding			Options Exercisable	
Range of exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$0.35 to $0.80	70,830	5.3	$0.44	70,830	$0.44
$1.55 to $1.90	23,429	4.1	$1.71	23,429	$1.71
$2.81 to $2.99	378,500	8.0	$2.91	28,500	$2.81
$6.00	18,800	2.4	$6.00	18,800	$6.00
	491,559			141,559	

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, 2005		$0.00
Granted		$0.00
Canceled or expired		$0.00
Vested		$0.00
Non-vested at December 31, 2006		$0.00
Granted	378,500	$2.06
Canceled or expired		$0.00
Vested	(28,500)	$1.96
Non-vested at December 31, 2007	350,000	$2.07

As of December 31, 2007, there was $599,356 of unrecognized compensation cost related to 350,000 nonvested stock options granted in 2007 under the existing stock incentive plan, the 2000 Plan. Unrecognized compensation cost of $376,320 and $223,036 will be recognized on a straight line basis over a vesting period of 28 and 21 months for 200,000 and 150,000 of the stock options granted, respectively.

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

(9) Related Party Transactions

Related party transactions which are not disclosed elsewhere in these consolidated financial statements are discussed in the following paragraphs:

At December 31, 2007, we owned 0.07% of the common stock of Drillmar, Inc. (Drillmar) and Drillmar Energy, Inc. (Drillmar Energy). Our Chairman, Ivar Siem, and one of our Directors, Harris A. Kaffie, beneficially own 32.4%, and 22.1%, respectively, of Drillmar s common stock and 21.3% and 7.6%, respectively, of Drillmar Energy s common stock. Messrs. Siem and Kaffie are both Directors of Drillmar, and Mr. Siem is Chairman and President of Drillmar.

On March 31, 2006, we purchased 334 shares of common stock in Drillmar Energy for $334 in a private placement offering by Drillmar to its shareholders on a proportionate basis to their current ownership percentage in Drillmar.

On May 25, 2006, we purchased 2 shares of common stock in Drillmar (an affiliate of Drillmar Energy) for $563 in a private placement offering by Drillmar to its shareholders on a proportionate basis to their current ownership percentage in Drillmar. This investment represented 0.07% of the total offering.

On September 25, 2006, we participated in an issuance of callable notes by Drillmar in proportion to our 0.07% interest in Drillmar. We were issued a note in the amount of $280. The note is callable by Drillmar at any time on or after three months from the date of issuance and accrues interest at 3% per annum, which is due and payable at maturity. The note would mature on January 1, 2009. The note was called and repaid with accrued interest in January 2008.

We entered into an agreement with Drillmar effective as of February 1, 2003, whereby we provided and charged for office space. This agreement terminated December 31, 2006. Our shares of Drillmar and Drillmar Energy were sold in January 2008. We recorded a gain of approximately $6,000 on the sale of these assets in January 2008.

(10) Leases

We have various operating leases that extend through April 2017. Certain of these operating leases are non-cancelable through May 2010. In March 2003, we entered into a sublease agreement expiring December 31, 2006 for certain of our office space with TexCal Energy (GP) LLC, formerly Tri-Union Development Corporation. During 2006, our annual receipts from this sublease were approximately $78,000.

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

The following is a schedule of future minimum lease payments under noncancelable operating leases exceeding one year at December 31, 2007:

Years Ending December 31,	Future Minimum Lease Payments
2008	$ 103,266
2009	107,051
2010	172,646
	$ 382,963

Rent expense on operating leases, net of sublease income and other rental reimbursements, for the years indicated are as follows:

Years Ended December 31,	Rent Expense
2007	$ 102,980
2006	$ 78,815

(11) 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 an employment agreement effective May 1, 2007, we are obligated to pay a base salary of $175,000 per year for the three-year term of the agreement.

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

(12) Business Segment Information

Our income producing operations are conducted in two principal business segments: (i) pipeline transportation services and (ii) oil and gas exploration and production. Intercompany revenue and expenses are eliminated in consolidation. Information concerning these segments for the years ended December 31, 2007 and 2006 is as follows:

	Revenues	Operating Income (Loss) (1)	Identifiable Assets (2)	Depletion, Depreciation and Amortization (3)
Year Ended December 31, 2007:				
Pipeline transportation	$ 2,494,406	$ (1,219,066)	$ 5,769,899	$ 413,342
Oil and gas exploration and production	517,411	(175,823)	344,541	135,650
Other		(475,263)	4,829,392	5,712
Consolidated	$ 3,011,817	(1,870,152)	$ 10,943,832	$ 554,704
Other income		248,637		
Loss before income taxes		$ (1,621,515)		
Year Ended December 31, 2006:				
Pipeline transportation	$ 1,939,894	$ (228,460)	$ 6,360,814	$ 353,472
Oil and gas exploration and production	2,358,814	1,032,681	851,668	139,643
Other		(472,113)	4,732,016	8,943
Consolidated	$ 4,298,708	332,108	$ 11,944,498	$ 502,058
Other income		595,435		
Income before income taxes		$ 927,543		

(1) Consolidated income (loss) from operations includes $469,551 and $463,170 in unallocated general and administrative expenses, and unallocated depletion,

depreciation, amortization and impairment of $5,712 and $8,943 for the years ended December 31, 2007 and 2006, respectively. All unallocated amounts are included in Other .

(2) See the supplemental disclosures for oil and gas producing activities for discussion of capitalized costs incurred for oil and gas production operations. Capital expenditures of $111,552 and $262,684 were recorded for pipeline operations for the years ended December 31, 2007 and 2006, respectively.

(3) Pipeline depletion, depreciation and amortization include a provision for pipeline abandonment of $48,595 for the years ended December 31, 2007 and 2006. Oil and gas

depletion, depreciation, amortization and impairment includes a provision for abandonment costs of platforms and wells of $99,147 and $34,694 for the years ended December 31, 2007 and 2006, respectively.

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

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, 2007:			
Apex Oil & Gas	$	$ 809,420	$ 809,420
W&T Offshore	$	$ 519,866	$ 519,866
Gryphon Exploration Co.	$	$ 341,406	$ 341,406
Year Ended December 31, 2006:			
Hydro Gulf, LLC (formerly Spinnaker Exploration Company)	$ 1,469,132	$	$ 1,469,132
Fidelity Exploration and Production Company	$ 889,682	$	$ 889,682

(13) 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 Securities and Exchange Commission and SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*.

Associated with our non-operating interest in High Island Block A-7, we recognized gross gas and oil sales revenues of approximately $200,000 and $1.5 million in 2007 and 2006, respectively, and lease operating expenses of approximately $200,000 and $430,000 in 2007 and 2006, respectively. Our working interest is approximately 8.9%. In September 2005, the two wells in High Island Block A-7 were successfully recompleted and resumed production at significantly higher rates. One of the wells produced throughout 2006, however, it ceased production during 2007. The second well ceased production in February 2006. We non-consented to a recompletion of the second well.

Associated with our non-operating interest in High Island Block 37, we recognized gross gas and oil sales revenues of approximately $300,000 and $0.9 million in 2007 and 2006, respectively, and lease operating expenses of approximately $32,000 and $27,000 in 2007 and 2006, respectively. We have a working interest of approximately 2.8% in two producing wells in the block, however, one of the wells is currently shut-in. Current production is approximately 3 MMcf of gas per day from a single well.

Associated with our non-operated interest in High Island Block 115, we recognized gross gas and oil sales revenues of approximately $30,000 and lease operating expenses of approximately $8,000 in 2007. We have a working interest of 2.5% in one zone of a single well in the lease. The well is currently producing approximately 9 MMcf per day.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
Estimated Quantities of Proved Oil and Gas Reserves Unaudited

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, 2007 and 2006. 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.

Quantity of Oil and Gas Reserves	Oil (Bbls)	Gas (Mcf)
Total proved reserves at December 31, 2005:	887	341,553
Revisions to previous estimates	1,089	78,640
Extensions, discoveries, improved recovery and other additions		
Purchase of reserves in place		
Sales of reserves in place		
Production	(1,823)	(312,146)
Total proved reserves at December 31, 2006	153	108,047
Revisions to previous estimates	64	(22,045)
Extensions, discoveries, improved recovery and other additions	806	164,456
Purchase of reserves in place		
Sales of reserves in place		
Production	(177)	(72,787)
Total proved reserves at December 31, 2007	846	177,671
Proved developed reserves:		
December 31, 2007	846	177,671
December 31, 2006	153	108,047
Total proved reserves:		
December 31, 2007	846	177,671
December 31, 2006	153	108,047

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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, 2007
Unproved properties and prospect generation costs not being amortized	$
Proved properties being amortized	751,175
Total capitalized costs	751,175
Accumulated depreciation, depletion and amortization	(675,855)
Net capitalized costs	$ 75,320

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,	
	2007	2006
Costs incurred:		
Acquisition of proved properties	$	$
Acquisition of unproved properties		
Exploration costs		
Development costs		15,700
Total costs incurred	$	$ 15,700

We did not incur costs in the acquisition of oil and gas properties in 2007 or 2006.

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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, 2007	2006
Revenues from oil and gas producing activities	$ 517,411	$ 2,358,814
Production costs	(240,317)	(457,312)
Depreciation, depletion, and amortization	(135,650)	(139,643)
Pretax income from producing activities	141,444	1,761,859
Income tax expense/estimated loss carryforward benefit	(354)	(27,883)
Results of oil and gas producing activities (excluding corporate overhead and interest costs)	$ 141,090	$ 1,733,976

Standardized Measure of Discounted Future Net Cash Flows
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, 2007	2006
Future cash inflows	$ 1,342,000	$ 605,000
Future development and dismantlement costs	(395,000)	(432,000)
Future production costs	(129,000)	(126,000)
Future income taxes	(278,120)	(15,980)
10% discount factor	(70,620)	27,720
Standardized measure of discounted future net cash inflows (outflows)	$ 469,260	$ 58,740

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: (1) multiplying estimated quantities of proved reserves to be produced during each year by year-end prices and (2) 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 carryforwards. 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 Statement 69 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,	
	2007	2006
Sales and transfers, net of production costs	$ (277,094)	$ (1,901,502)
Net change in sales and transfer prices, net of production costs	16,380	(959,002)
Extension, discoveries and improved recovery, net of future production and development costs	987,094	
Development costs incurred during the period that reduced future development costs	76,290	
Changes in estimated future development cost	(252)	(310,553)
Revisions of quantity estimates	(132,353)	(235,475)
Accretion of discount	8,900	319,000
Net change in income taxes	(255,680)	1,054,340
Change in production rates (timing) and other	(12,765)	(13,468)
Net change	$ 410,520	$ (2,046,660)

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Item 8. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

None.

Item 8A(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 Principal Accounting and Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based upon this evaluation, as of December 31, 2007, the Chief Executive Officer and Principal Accounting and Financial Officer concluded that our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act, are recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Principal Accounting and Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management s Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-5(f) under the Exchange Act). Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. 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, 2007, 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 Securities and Exchange Commission that permit us to provide only management s report in this annual report.

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

Changes In Internal Controls 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 8B. Other Information

None.

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PART III

Item 9. Directors, Executive Officers, Promoters, Control Persons and Corporate Governance; Compliance with Section 16(a) of the Exchange Act

The information required by Item 9 is incorporated by reference to our definitive proxy statement relating to our 2008 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 10. Executive Compensation

The information required by Item 10 is incorporated by reference to our definitive proxy statement relating to our 2008 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. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity Compensation Plan Information

The following table represents information with respect to the 2000 Stock Incentive Plan as of December 31, 2007:

	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plans approved by security holders	491,559	$ 2.61	274,040

The information required by Item 403 of Regulation S-B is incorporated by reference to our definitive proxy statement relating to our 2008 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. Certain Relationships and Related Transactions, and Director Independence

The information required by Item 12 is incorporated by reference to our definitive proxy statement relating to our 2008 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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Item 13. Exhibits
(a) 1. Exhibits

	No.	Description
	3.1(1)	Amended and Restated Certificate of Incorporation of the Company.
	3.2(9)	Amended and Restated Bylaws of the Company.
	4.1(2)	Specimen Certificate of our Company common stock.
	4.2(11)	Code of Ethics applicable to the Chairman, Chief Executive Officer and Senior Financial Officer.
	4.3(7)	Form of Promissory Note issued pursuant to the Note and Warrant Purchase Agreement dated September 8, 2004.
*	10.1(3)	Blue Dolphin Energy Company 2000 Stock Incentive Plan.
*	10.2(4)	Amendment to the Blue Dolphin Energy Company 2000 Stock Incentive Plan.
	10.3(5)	Second Amendment to the Blue Dolphin Energy Company 2000 Stock Incentive Plan.
	10.4(6)	Purchase and Sale Agreement by and between Blue Dolphin Pipe Line Company and MCNIC, dated February 1, 2002.
	10.5(7)	Sale of American Resources Offshore, Inc. Common Stock Agreement between Blue Dolphin Exploration Co. and Ivar Siem, dated September 8, 2004.
	10.6(8)	Purchase and Sale Agreement by and between Blue Dolphin Energy Company, WBI Pipeline & Storage Group, Inc. and SemGas LP, dated October 29, 2004.
	10.7(10)	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.
	10.8(12)	Placement Agency Agreement by and between Blue Dolphin Energy Company and Starlight Investments, LLC dated May 27, 2005.
	10.9(13)	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.
**	21.1	List of Subsidiaries of the Company.
**	23.1	Consent of UHY LLP.
**	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	Gregory W. Starks 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	Gregory W. Starks Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.

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* Management Compensation Plan.
** Filed herewith.

(1) Incorporated herein by reference to Exhibits filed in connection with the definitive Proxy Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated October 13, 2004 (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 Exhibits filed in connection with the Proxy

Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated May 18, 2000 (Commission File No. 000-15905).

(4) Incorporated herein by reference to Exhibits 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 Exhibits filed in connection with the definitive Proxy Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated April 27, 2007 (Commission File No. 000-15905).

(6) Incorporated herein by reference to Exhibits filed in connection with Form 10-KSB of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated July 23, 2002 (Commission File No. 000-15905).

(7) Incorporated herein by reference to Exhibits 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 Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated December 6,

2004 (Commission File No. 000-15905).

(9) Incorporated herein by reference to Exhibits 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 Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated March 2, 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).

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Item 14. Principal Accountant Fees and Services

The information required by Item 14 is incorporated by reference to our definitive proxy statement relating to our 2008 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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SIGNATURES

In accordance with 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: March 31, 2008

In accordance with 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)	March 31, 2008
/s/ Gregory W. Starks Gregory W. Starks	Vice President, Treasurer and Secretary (Principal Accounting and Financial Officer)	March 31, 2008
/s/ Laurence N. Benz Laurence N. Benz	Director	March 31, 2008
/s/ John N. Goodpasture John N. Goodpasture	Director	March 31, 2008
/s/ Harris A. Kaffie Harris A. Kaffie	Director	March 31, 2008
/s/ Erik Ostbye Erik Ostbye	Director	March 31, 2008

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Exhibit Index

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	10.6(8)	Purchase and Sale Agreement by and between Blue Dolphin Energy Company, WBI Pipeline & Storage Group, Inc. and SemGas LP, dated October 29, 2004.
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** Filed herewith.

(1) Incorporated herein by reference to Exhibits filed in connection with the definitive Proxy Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated October 13, 2004 (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 Exhibits filed in connection with the Proxy

Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated May 18, 2000 (Commission File No. 000-15905).

(4) Incorporated herein by reference to Exhibits 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 Exhibits filed in connection with the definitive Proxy Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated April 27, 2007 (Commission File No. 000-15905).

(6) Incorporated herein by reference to Exhibits filed in connection with Form 10-KSB of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated July 23, 2002 (Commission File No. 000-15905).

(7) Incorporated herein by reference to Exhibits 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 Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated December 6,

2004 (Commission File No. 000-15905).

(9) Incorporated herein by reference to Exhibits 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 Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated March 2, 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).