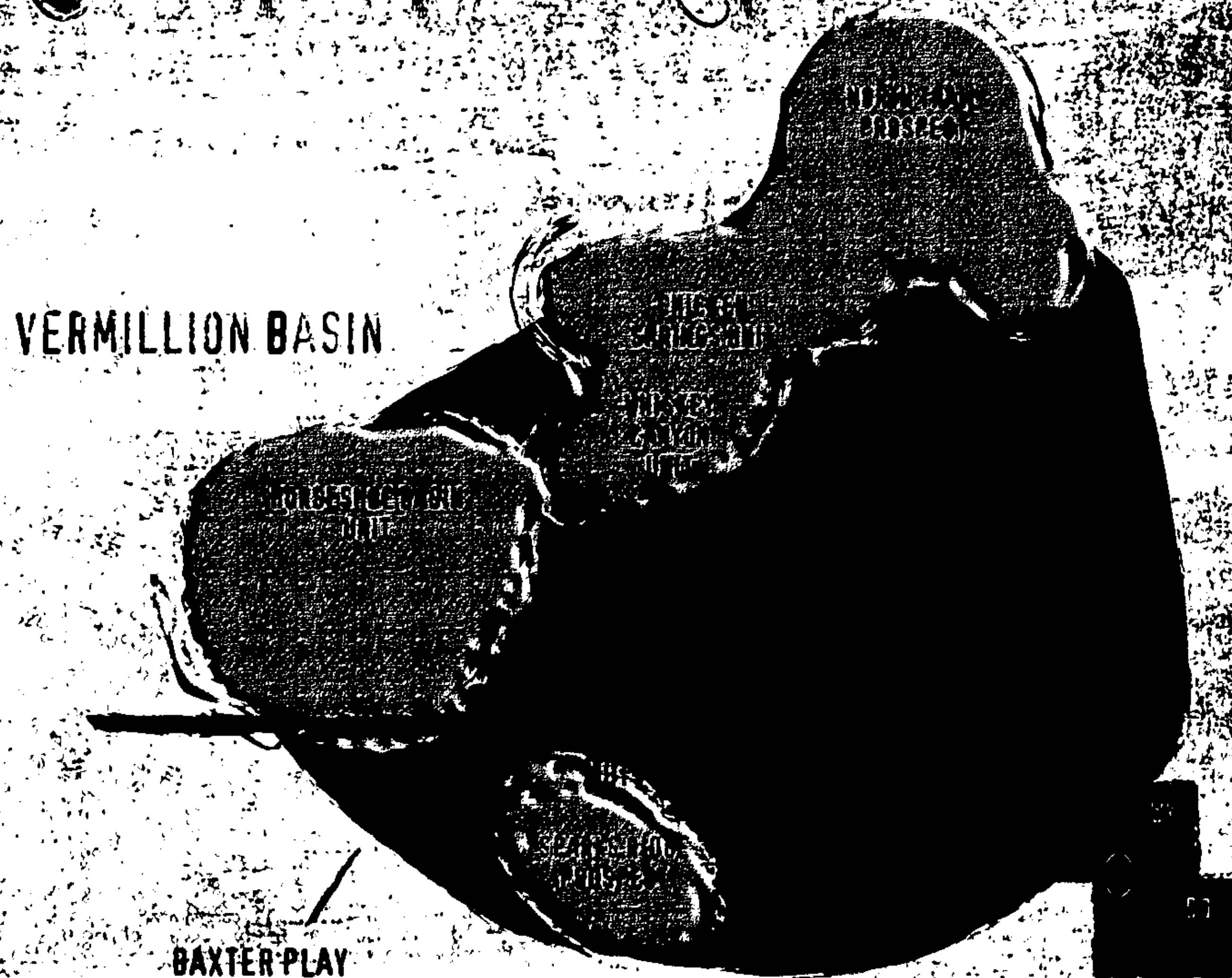
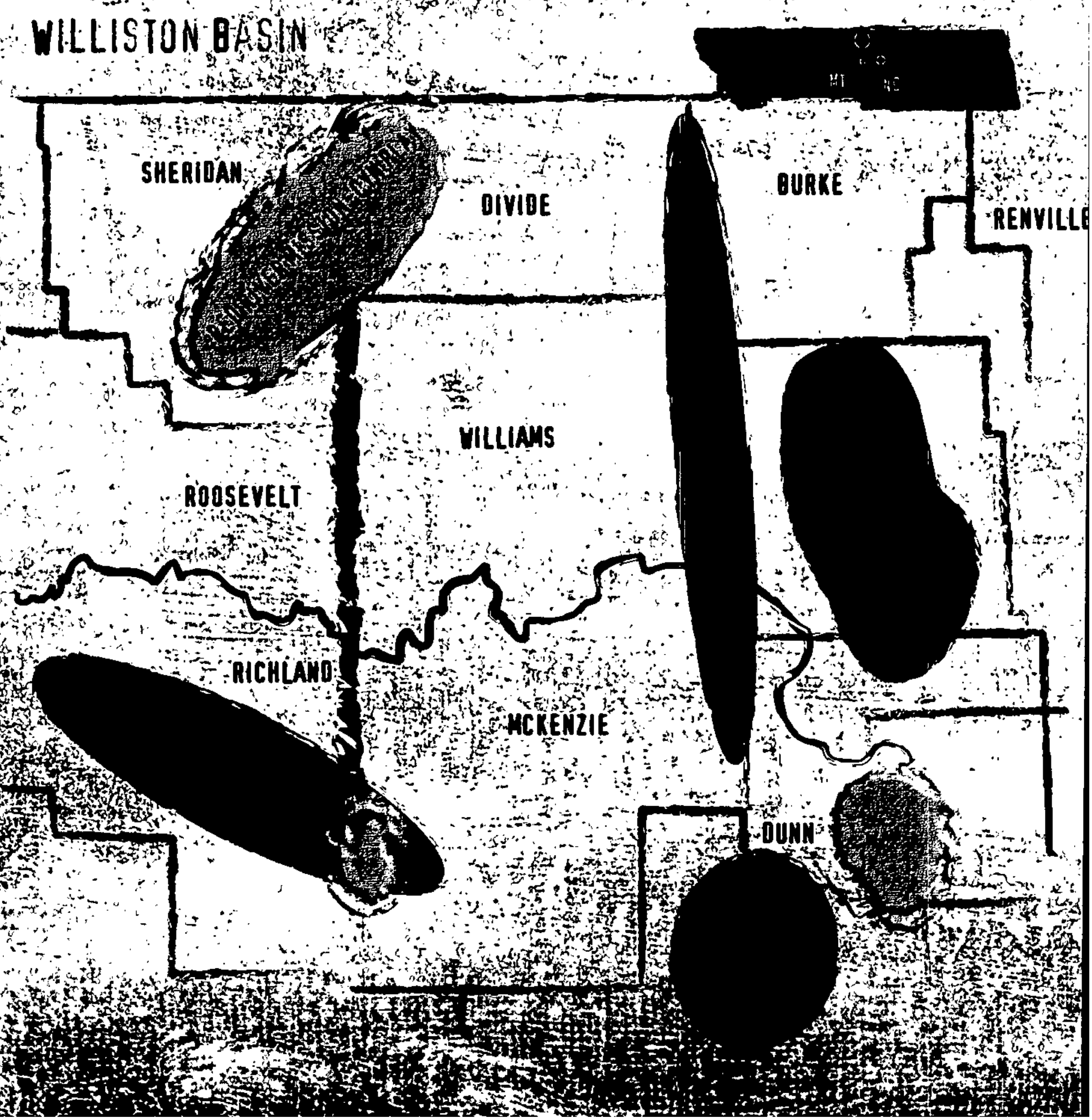
TRACKING PROGRESS

KODIAK

OIL & GAS CORP.

Kodiak Leasehold Area




WILLISTON BASIN
SHERIDAN
DIVIDE
BURKE
RENVILLE
WILLIAMS
ROOSEVELT
RICHLAND
MCKENZIE
DUNN

Letter to Our Shareholders

As Kodiak enters its seventh year, the Company has made great strides in positioning itself for future growth. Our core assets feature meaningful leasehold in two attractive, emerging shale plays where we are fortunate to have high working-interest ownerships. The Baxter shale gas play in the Vermillion Basin of Wyoming saw some promising wells drilled in 2007, by us and other E&P companies, and it will see continued activity in 2008. Our Bakken shale oil play in North Dakota's part of the Williston Basin is the focus of intense leasing competition due in part to numerous, significant oil discoveries throughout the Basin. Drilling and completion technology is contributing greatly to improving per-well economics in most every shale play in North America, and we expect the same for our projects. Moreover, our balanced exposure to crude oil and natural gas assets, a company strategy from the beginning, is providing positive operating cash flows. Significantly, we enter 2008 with a strong, conservative balance sheet that is free of debt or similar commitments.

Despite our first significant Vermillion Basin success, some hurdles remain to best unlock what we believe is a vast natural gas resource. To help climb the learning curve and push this play to the development stage, Kodiak is fortunate to have joined with a partner that brings some of the strongest technical people with respect to shale plays. We recently announced an exploration agreement with a subsidiary of Devon Energy Corp. whereby Devon earned an interest in our Vermillion leasehold in exchange for, among other things, drilling up to three wells to test the Baxter shale at Devon's sole cost and risk. The Devon transaction fits perfectly with our focus on creating drilling activity on our lands during the early stages of determining productive potential and ultimate recoveries.

With the Devon arrangement in place, the evaluation of the Baxter shale will continue. We are now able to focus the bulk of our 2008 capital expenditure program on the exciting North Dakota Bakken shale oil play. We expect our leasehold, which we believe is in an excellent fairway, to exceed 30,000 net acres in this emerging play. Industry data points from this part of the Bakken trend have been and continue to be encouraging. We plan to drill up to four Bakken shale wells in 2008, the first of which will spud in the late second quarter of 2008. Included in this well count will be two wells under a participation agreement with a large, private partner whereby both parties would own a 50% working interest in specific undeveloped lands that we announced in late 2007.

Kodiak remains lean at the corporate level with a total of 15 employees at our Denver headquarters, along with experienced contractors in the field. Kodiak has attracted a team of dedicated professionals that are integral to our success. We would like to sincerely thank each Kodiak employee for their hard work and devotion to making our company a success. Thanks also are extended to our shareholders and directors for their support and confidence in our team. We look forward to updating each and everyone throughout the year and invite you to track our success.

Lynn A. Peterson
President, Chief Executive Officer and Director

James E. Catlin
Chief Operating Officer
and Chairman of the Board

March 17, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2007
Commission file number: 001-32920

KODIAK
OIL & GAS CORP.

(Exact name of registrant as specified in its charter)

Yukon Territory	**N/A**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1625 Broadway, Suite 250 **Denver, Colorado 80202**	**(303) 592-8075**
(Address of principal executive offices)	(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock	**American Stock Exchange**

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

Title of Each Class
N/A

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

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

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

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

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

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

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

At June 30, 2007, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $424,213,769.

The number of shares of the registrant's Common Stock outstanding as of March 5, 2007, was 87,992,926.

DOCUMENTS INCORPORATED BY REFERENCE

Certain portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A not later than April 30, 2007, in connection with the Registrant's 2008 Annual Meeting of Shareholders, are incorporated herein by reference into Part III of this Annual Report on Form 10-K.

KODIAK OIL & GAS CORP.
FORM 10-K
TABLE OF CONTENTS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The statements contained in this annual report on Form 10-K that are not historical are "forward-looking statements," as that term is defined in Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties.

These forward-looking statements include, among others, the following:

- our business and growth strategies;
- our oil and natural gas reserve estimates;
- our ability to successfully and economically explore for and develop oil and gas resources;
- our exploration and development drilling prospects, inventories, projects and programs;
- availability and costs of drilling rigs and field services;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry; and
- the impact of environmental and other governmental regulation.

These statements may be found under "Risk Factors", "Management's Discussion and Analysis of Financial Condition and Results of Operation", "Business and Properties" and other sections of this annual report. Forward-looking statements are typically identified by use of terms such as "may", "will", "could", "should", "expect", "plan", "project", "intend", "anticipate", "believe", "estimate", "predict", "potential", "pursue", "target" or "continue", the negative of such terms or other comparable terminology, although some forward-looking statements may be expressed differently.

The forward-looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this annual report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to a number of factors, including:

- the failure to obtain sufficient capital resources to fund our operations;
- an inability to replace our reserves through exploration and development activities;
- unsuccessful drilling activities;
- a decline in oil or natural gas production or oil or natural gas prices;
- incorrect estimates of required capital expenditures;
- increases in the cost of drilling, completion and gas gathering or other costs of production and operations;

- impact of environmental and other governmental regulation, including delays in obtaining permits; and
- hazardous and risky drilling operations.

You should also consider carefully the statements under "Risk Factors" and other sections of this annual report, which address additional factors that could cause our actual results to differ from those set forth in the forward-looking statements.

All forward-looking statements speak only as of the date of this annual report. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview and Strategy

We are an independent energy company focused on the exploration, exploitation, acquisition and production of natural gas and crude oil in the United States. Our oil and natural gas reserves and operations are concentrated in two Rocky Mountain basins. Historically, we have explored for conventional and unconventional gas plays in the Green River Basin in Wyoming and Colorado, and for oil in the Williston Basin in Montana and North Dakota. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed a portfolio of proved reserves, development and exploratory drilling opportunities on high potential conventional and non-conventional oil and natural gas prospects. Significant prospects in our portfolio currently include:

- Vermillion Basin of southwest Wyoming: as of December 31, 2007, we controlled 25,178 net acres in this developing play where geologic targets include the Baxter Shale at a depth of 10,000 to 13,000 feet as well as other shallower producing zones. In the first quarter of 2008, we entered into an exploration and development agreement with Devon Energy Production Company, L.P. as part of our strategy to develop this play. After closing of this agreement, we control approximately 16,800 net acres in the Basin.
- Eastern Bakken oil play in Mountrail and Dunn Counties, North Dakota: in 2007 and in early 2008, we have acquired an interest under approximately 50,000 gross (30,000 net) acres in this highly prospective play.

Property Acquisition and Exploration Activities

As of December 31, 2007, we had several hundred lease agreements representing approximately 152,430 gross and 98,162 net acres in the Green River and Williston Basins.

In 2007, we made significant progress in increasing our acreage position in Dunn County, North Dakota, in the area we refer to as the Eastern Bakken play of the Williston Basin. As of December 31, 2007, we had acquired 29,487 gross acres and 18,089 net acres on the Fort Berthold Indian Reservation. Additional acreage has been leased in 2008 or is in the approval process with the Bureau of Indian Affairs ("BIA"). We expect our leased acreage in this area to total over 30,000 net acres if all leases that have been executed by the landowners are approved by the BIA. The majority of our lands in this prospect area are administered by the BIA on behalf of the individual members of the Three Affiliated Tribes Fort Berthold Indian Reservation. Typically these lands are acquired through a private negotiation with the individual land owners and the Three Affiliated Tribes and have a primary lease term of five years. The land owner typically retains an 18% landowner royalty. In most cases, these lands require an annual delay rental of $2.50 per net acre.

Our acreage located in the Williston Basin outside of the Fort Berthold Indian Reservation is held primarily on the basis of fee leases. These leases typically carry a primary term three to five years with landowner royalties of 12.5% to 18.5%. In most cases we obtain "paid up" leases that do not require annual delay rentals.

The majority of our acreage located in the Green River Basin is federal land administered by the U.S. Bureau of Land Management ("BLM"). Typically these lands are acquired through a public auction and have a primary lease term of ten years. The U.S. Department of Interior normally retains a 12.5% royalty interest in these lands. Most of our lands in this area are encompassed within federal operating units approved by the BLM that allow for the orderly exploration and development of the federal lands. In most cases, these federal lands require an annual delay rental of $1.50 per net acre.

In February 2008, we entered into an exploration agreement ("Devon Agreement") with Devon Energy Production Company, L.P., a wholly owned subsidiary of Devon Energy Corp ("Devon") under which Devon earned an interest in our leasehold interests in the Vermillion Basin in exchange for, among other things, drilling up to three wells at Devon's sole cost and risk by November 15, 2009. As part of the Devon Agreement, we and Devon have set forth terms and conditions that create an Area of Mutual Interest (AMI) for the exploration, leasing, and development of certain of our Vermillion Basin properties. Upon completion of each of the three wells, we will have a 50% working interest in each well, proportionately reduced in the event of third-party interest. By drilling the three wells, Devon will earn, among other considerations, 50% of our leasehold interest to all depths within the AMI, excluding any leasehold already jointly held by and between us and Devon and any existing Kodiak wellbores.

As a result of the Devon Agreement, our leasehold interests in the Vermillion Basin total approximately 46,000 gross (16,000 net) acres. The AMI will expire after a period of five years, unless extended by mutual agreement of both parties. Each party has agreed to a proportionate share of any interest or lease acquired within the participating area. Under the terms of the agreement, Devon will serve as operator but both parties will collaborate by each providing technical input and drilling and completion expertise in order to best develop the AMI properties.

The following table sets forth our gross and net acres of developed and undeveloped oil and natural gas leases as of December 31, 2007.

	Undeveloped Acreage(1)		Developed Acreage(2)		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Green River Basin						
Wyoming(3)(4)(5)	41,451	27,896	1,400	848	42,851	28,744
Colorado	12,004	9,571	—	—	12,004	9,571
Williston Basin						
Montana	39,470	23,847	800	400	40,270	24,247
North Dakota	44,136	25,357	3,040	1,800	47,176	27,157
Other Basins						
Wyoming	10,129	8,443	—	—	10,129	8,443
Acreage Totals	**147,190**	**95,114**	**5,240**	**3,048**	**152,430**	**98,162**

(1) Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage includes proved reserves.

(2) Developed acreage is the number of acres that are allocated or assignable to producing wells or wells capable of production.

(3) Includes 4,784 gross and net undeveloped acres sold effective January 2008.

(4) Excludes 10,261 gross (6,127 net) acres that can be earned pursuant to existing farm-in agreements.

(5) As a result of the Devon Agreement, the net acres in the Green River Basin will be reduced by approximately 8,400 net acres.

Substantially all of the leases summarized in the preceding table will expire at the end of their respective primary terms unless (i) the existing lease is renewed; (ii) we have obtained production from the acreage subject to the lease prior to the end of the primary term, in which event the lease will remain in effect until the cessation of production; or (iii) it is contained within a Federal unit. The following table sets forth the gross and net acres of undeveloped land subject to leases that will expire during the next three years and have no options for renewal or are not included in Federal units:

Year Ending	Expiring Acreage Gross	Expiring Acreage Net
December 31, 2008	1,513	917
December 31, 2009	10,542	6,057
December 31, 2010	31,508	18,676
Total	43,563	25,650

All of our leases grant us the exclusive right to explore for and develop oil, natural gas and other hydrocarbons and minerals that may be produced from wells drilled on the leased property without any depth restrictions. Our federal leases generally include restrictions on drilling during the period of November 15 to April 30. These restrictions are intended to protect big game winter habitat and do not restrict operations or maintenance of production facilities. In most cases, our natural gas prospects are within a reasonable distance of natural gas pipelines, therefore limiting the construction of gathering systems necessary to tie into existing lines. Our oil is transported mostly by trucks and, if available, pipelines.

Production, Average Sales Prices, and Production Costs

We earned revenues on natural gas production of $1.0 million and on oil production of $6.8 million and incurred $1.8 million in production costs for the year ended December 31, 2007. Our gas production comes from ten wells in the Green River Basin, three of which we operate and seven of which we have a non-operating economic interest, and the natural gas associated with our oil wells in the Williston Basin. Our oil revenues are derived primarily from eight wells that we operate in the Williston Basin. Sales volumes, prices received, and production costs are summarized in the following table:

	Fiscal Year ended December 31, 2007	2006	2005
Sales Volume:			
Gas (Mcf)	200,191	117,324	31,751
Oil (Bbls)	102,914	61,966	2,699
Price:			
Gas ($/Mcf)	$ 5.26	$ 5.56	$ 7.11
Oil ($/Bbls)	$ 65.72	$ 55.52	$ 51.89
Production costs ($/BOE):			
Lease operating expenses	$ 6.87	$ 7.54	$ 21.60
Production and property taxes	$ 5.30	$ 3.95	$ 3.66
Gathering, Transportation and Marketing	$ 0.73	$ 0.34	$ 0.00

Capital Expenditures

We anticipate net capital expenditures of $12.6 million in 2008 compared to approximately $45.1 million spent in 2007. The following tables set forth our capital expenditures for the year ended December 31, 2007 and our planned capital expenditures for our principal properties in 2008. Net capital expenditures include both cash expenditures and accrued expenditures and are net of proceeds from divestitures. The 2008 estimated expenditures do not include the costs to drill additional wells that will help further evaluate our properties in the Vermillion Basin. These wells are to be drilled at the sole cost of Devon under the Devon Agreement.

Project Location	2007 Net Capital Expenditures ($000)	2008 Estimated Net Capital Expenditures ($000)
Wyoming		
Vermillion Basin wells and related infrastructure	$31,982	$ 743
Other Wyoming wells and related infrastructure	1,112	(845)
Acreage/Seismic	3,390	1,350
Total Wyoming	36,484	1,248
Williston Basin		
Mission Canyon/Red River wells and related infrastructure	5,034	1,127
Bakken wells and related infrastructure	1,173	9,616
Acreage/Seismic	2,424	621
Total Williston Basin	8,632	11,363
Total All Areas	$45,116	$12,612

Drilling Activity

All of our drilling activities are conducted on a contract basis by independent drilling contractors. We do not own any drilling equipment. The following table sets forth the number and type of wells that we drilled during the years ended December 31, 2007, 2006 and 2005. In addition, as of December 31, 2007, we have 2 gross (0.25 net) wells in progress, neither of which we operate.

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Oil wells	2	1.0	3	1.9	3	1.5
Gas wells	—	—	3	1.5	2	1.0
Non-Productive(1)	1	0.5	0	0	0	0
Exploratory wells, completed as:						
Oil wells	—	—	0	0	2	1.0
Gas wells	3	2.8	2	2.0	4	1.5
Non-Productive(1)	4	1.8	1	0.5	1	0.3
Total	**10**	**6.1**	**9**	**5.9**	**12**	**5.3**

(1) A non-productive well is a well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well; also known as a dry well or dry hole.

Productive Wells

As part of our corporate strategy, we seek to operate our wells where possible and to maintain a high level of participation in our wells by investing our own capital in drilling operations. The following table summarizes our productive wells as of December 31, 2007, all of which are located in the Rocky Mountain region of the United States. Productive wells are wells that are producing or capable of producing, including shut-in wells.

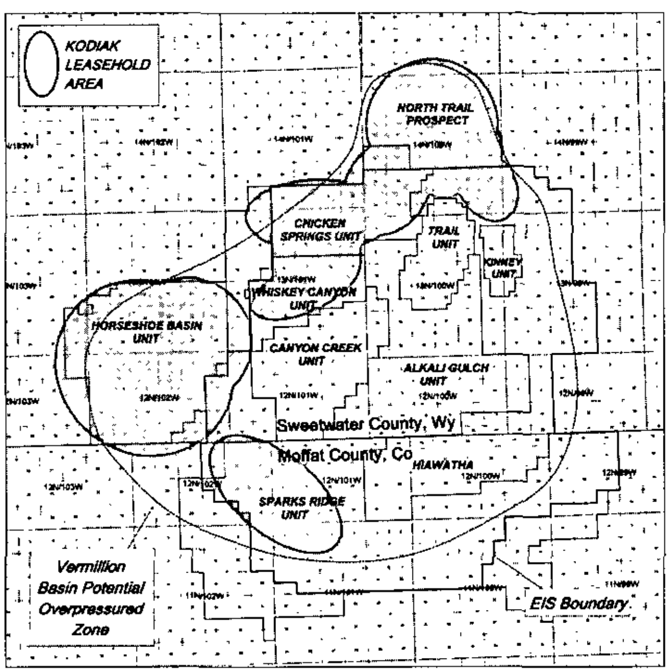
	Operated		Non-operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin						
Oil wells	9	4.7	—	—	9	4.7
Wyoming/Colorado						
Gas wells	7	6.5	7	3.5	14	10.0
Total	**16**	**11.2**	**7**	**3.5**	**23**	**14.7**

Operations in the Green River Basin of Wyoming and Colorado

Vermillion Basin Deep—Baxter Shale and Frontier and Dakota Sandstone

Our primary leaseholdings in the Green River Basin are located in an area referred to as the Vermillion Basin. In this geologic region, we believe there is natural gas trapped in various sands, coals and shales at depths ranging from 2,000 feet to nearly 15,000 feet. The primary target of our current exploration efforts in this area is the over-pressured Baxter Shale at depths to approximately 13,000 feet. As of December 31, 2007, we controlled approximately 40,000 gross (25,178 net) acres in this basin and have drilled, completed and operate four gross (3.8 net) wells. After closing of the Devon Agreement, we control approximately 40,000 gross (16,778 net) acres in this basin.

The following map displays our general area of operation in the Vermillion Basin:



In December 2006 and early 2007, we completed drilling of our first two deep gas wells in these over-pressured formations, the North Trail State #4-36 and North Trail #1-33 wells located in

Sweetwater County, Wyoming. We operate and have a 100% working interest ("WI") and 80% and 82.5% net revenue interest ("NRI"), respectively, in the wells. The wells were drilled to total depths of 14,330 feet and 14,500 respectively. In 2007, the Company horizontally drilled the first gaseous interval in the Baxter Shale, at an approximate vertical depth of 11,700 feet, on its NT Federal #4-35H well (100% WI, 82.5% NRI). While the well encountered gas shows in several fractured intervals that were intercepted by the 1,655 feet of horizontal lateral in one of the targets within the Baxter shale, the production results were not commercial and this lateral has been abandoned. The Company re-entered the NT Federal #4-35H well bore during the third quarter of 2007, sidetracked and vertically drilled the Baxter, Frontier and Dakota Formations to a total depth of 14,434 feet. The Company obtained full cores over five sixty-foot intervals throughout the Baxter Shale. These cores have been evaluated for a number of factors including gas in place, rock properties and mechanics. Completion work on this well to-date includes the fracture stimulation of the Frontier and Dakota Sands and the first stage of the Baxter Shale completed in late December 2007. Upon full operation of its related sales pipeline, this well is expected to flow at approximately 100 to 200 Mcf per day. We will continue to evaluate the data derived from these activities and currently plan to fracture stimulate the upper Baxter zones at a later date.

Also in 2007, we completed drilling operations on the Horseshoe Basin #5-3 well (80% WI, 68% NRI, Kodiak operated) located on the western edge of the prospective producing area. This well was drilled vertically to a depth of 13,534 feet to evaluate the potential of the Mesaverde formations, the Baxter Shale and the Frontier Formation. The well was a significant step out and it is approximately 6 miles from the closest producing well. Following fracture stimulation of the Baxter shale in November, the initial twenty-four hour flowback rate was estimated at 3.0 million cubic feet (MMcf) of natural gas with a 16/64" choke and 3,500 psia of flowing casing pressure. Subsequently, the well was tested for 48 hours through a test separator and stabilized at approximately 2.0 MMcf per day with 350 barrels of condensate per day. The well is currently waiting on the completion of a gathering pipeline which is expected to be in place by mid-summer 2008. As part of the Devon Agreement, Devon will earn an increased ownership in this well and as a result, our interest will be reduced to 50% WI and 42% NRI.

Our 2008 exploration efforts in the Vermillion Basin prospect area will be driven by Devon under its drilling plans as described in the Devon Agreement. It is currently expected that the first drilling activity will be conducted as an offset well to the Horseshoe Basin #5-3 well. A drilling permit for the Horseshoe Basin #1-4 well has been submitted and drilling is anticipated during the summer and fall months as lease stipulations expire and the locations are accessible. While drilling plans are still being finalized, we anticipate this will be a vertical well and will evaluate only the Baxter Shales and not the deeper formations tested in the Horseshoe Basin #5-3. Concurrently with the drilling of this well we anticipate the acquisition of 3-D seismic covering the Horseshoe Basin Unit to help facilitate a development program in 2009 and beyond. We have completed the acquisition of approximately 43 square miles of 3-D seismic on the northern block of our acreage which includes portions of our Chicken Springs and Chicken Ranch Federal Units, as well as land currently not included in federal units. Processing and interpretation should be completed in early 2008 which will better define the future exploration and development of the basin. While no specific drilling locations have yet been determined, we anticipate that additional wells will be drilled under the Devon Agreement in this area as a result of the seismic evaluation.

Kodiak's operated wells in the Vermillion Basin were shut in during the 2007 summer and fall months due to adverse Rockies gas prices. In December 2007, we commenced production on these wells as stronger gas prices were received during the winter months. Additionally, with the initial operations of the Rockies Express Pipeline that went into partial service during the first quarter of 2008, improved natural gas prices in the Rockies production area are expected with the increased capacity to natural gas consumption markets.

Vermillion Basin Shallow—Almond Sandstone, Almond Coals and Ericson Sandstone

During the last part of 2006, we participated in the drilling of three non-operated shallow wells (50% WI) to test the Almond sands at an approximate depth of 5,500 feet. These wells were all placed into production in the first quarter of 2007 at rates between 440-600 Mcf per day and are currently producing at rates of 50-300 Mcf per day. These same sands are present in the deeper wells described above; however, we are currently not attempting to extract gas from the sands, but intend to produce from the sands at a later time.

Sale of Sand Wash Basin Prospect Mancos Shale

In January 2008, we completed the sale of 4,784 gross and net acres in an exploratory Mancos Shale gas prospect located in the Sand Wash Basin in Moffat County, Colorado for $1.2 million. We retained a 5% overriding royalty in these properties as well as 100% working interest ownership in the remaining 3,770 acres. We believe the remaining acreage is prospective for production from the Mancos Shale and Niobrara Formation at a shallower depth than that divested.

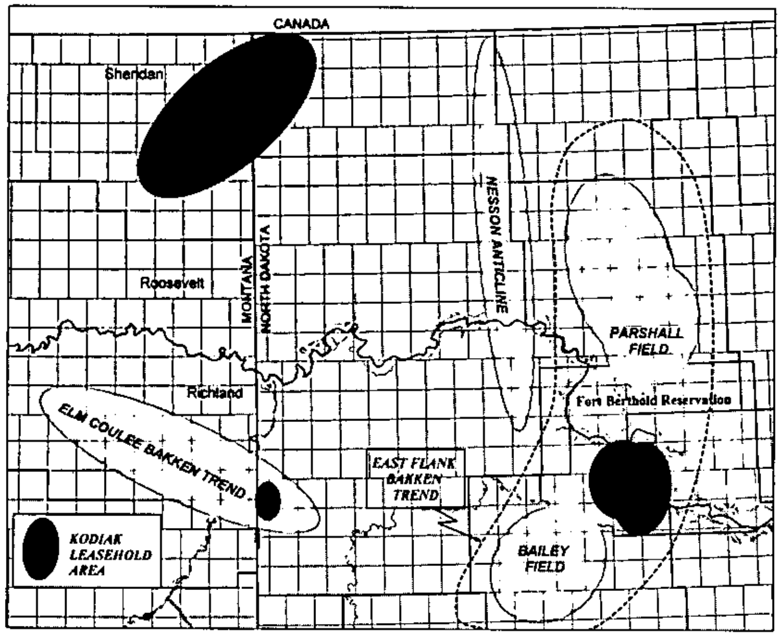
Other Wyoming and Colorado Prospects

In addition to the Vermillion Basin and Sand Wash Basin acreage, we have other geologic prospects that we have generated on 16,874 gross (13,026 net) acres that we have generated in Wyoming and are continuing to develop through seismic evaluation and exploratory and development drilling. This includes our Popskull prospect (6,775 gross, 5,089 net acres) where we participated in the drilling of one dry hole in 2007. This well was drilled to a depth of 12,925 feet to test the fluvial Muddy Formation. This Formation produces to the north of the prospect in the Sand Dunes Field that has produced approximately 20 million barrels of oil (MMBO) and to the south in the Big Muddy-Glenrock Field that has produced over 83 MMBO to date. A 3-D seismic study is anticipated in 2008 before any further drilling is expected.

In the Bighorn Basin of Wyoming we have 3,354 gross and net acres in our Elk Creek Prospect. The primary targets of this geologic prospect are the Frontier and Muddy Formations at depths to 12,500 feet. We concluded our acreage acquisition during the first quarter of 2008 and we anticipate participating in a 3-D seismic study in 2008. The prospect acreage is offset to the northwest by the Fritz Field that has produced 1.5 MMBO while to the southeast the Dobie Creek Field has produced 356,000 barrels of oil and 7.6 Bcf of natural gas from 13 wells and the Five Mile Field which has produced over 1.8 MMBO and 73.2 Bcf of natural gas from 35 wells.

Operations in the Williston Basin of Montana and North Dakota

The following map displays our areas of operation in the Williston Basin:



Red River-Mission Canyon Play—Sheridan County, Montana and Divide County, North Dakota

The primary producing objectives in this prospect area are the Mission Canyon and the Red River formations at approximate depths of 8,000 feet and 11,000 feet, respectively. During 2007, Kodiak participated in the drilling of five geologic prospects that were defined by 3-D seismic. We completed two of these wells and three were determined to be unproductive. Kodiak will monitor the production from the recently drilled wells before further stepouts are drilled. The Company has identified several additional prospects within its acreage that may be drilled during 2008 subject to the results of seismic evaluation. We have recently completed the acquisition of an approximate 18 square mile 3-D seismic program over a portion of this acreage.

Bakken Formation—McKenzie and Dunn Counties, North Dakota

Kodiak has three wells in McKenzie County producing from the Bakken Formation near the North Dakota and Montana state line. The three wells were put on production in late 2006 and early 2007 and have produced approximately 115,000 BOE through December 31, 2007. One of the three wells has never been fracture stimulated and we expect such procedure to be completed in early 2008. The Company has at least two undeveloped locations offsetting these wells which could be drilled in 2008.

We have continued our ongoing acreage acquisition program in Dunn County, North Dakota where the primary objective is the dolomitic, sandy interval sandwiched between the two Bakken Shales at an approximate vertical depth of 10,000 feet. As of December 31, 2007, we had acquired 29,487 gross acres and 18,089 net acres on the Fort Berthold Indian Reservation. Additional acreage has been leased in 2008 or is in the approval process with the BIA. We expect our leased acreage in this area to total over 30,000 net acres if all leases that have been executed by the landowners are approved by the BIA. This acreage is in a trend bordered by producing wells drilled by, among others, EOG Resources, Inc. and Whiting Petroleum Corp. to the north and Marathon Oil Corp. and ConocoPhillips to the west and south.

We are permitting seven locations on our Tall Bear Prospect, our most southern block of acreage in the area, which includes approximately 10,184 gross acres and 7,002 net acres. Subject to obtaining a permit to drill from the Bureau of Land Management and the Bureau of Indian Affairs, drilling activity should commence in the second quarter of 2008. We will operate and currently own an approximate 70% working interest in the proposed drill site and acreage block but anticipate reducing our working interest to an approximate 50%.

In the third quarter of 2007, we entered into a letter of intent with a private, independent exploration and production company to jointly lease and develop certain prospective lands north and northwest of our Tall Bear acreage block. Under this letter of intent and subsequent participating agreement, Kodiak and its partner each will have an undivided 50% working interest in the properties. Under the participating agreement, we have committed to participate in the drilling of two horizontal wells that will evaluate the Bakken Formation. We own approximately 13,946 gross and 6,973 net acres in this block of acreage. Permitting procedures began in the first quarter of 2008 with drilling scheduled for the second half of 2008. Kodiak and its partner will share operations with each entity operating certain properties.

In addition, we have acquired 4,114 gross and net acres under lands located outside the boundaries of the two aforementioned prospect areas. We own 100% of these lands and will most likely maintain a high working interest in these lands until further exploration work begins to delineate the play.

Our Reserves

Netherland Sewell & Associates, Inc., a petroleum engineering consulting firm, audited our estimated reserves as of December 31, 2007, and prepared our estimated reserves as of December 31, 2006. Sproule Associates Inc., a petroleum engineering consulting firm, estimated our reserves as of December 31, 2005. All of our reserves are located within the continental United States. The reserve estimates are developed using geological and engineering data and interests and burdens information developed by our company. Reserve estimates are inherently imprecise and remain subject to revisions based on production history, results of additional exploration and development drilling, results of secondary and tertiary recovery applications, prevailing oil and natural gas prices, and other factors. You should read the notes following the table below and the information following the notes to our audited financial statements for the years ended December 31, 2007 and 2006 included elsewhere in this Form 10-K in conjunction with the following reserve estimates:

	As of December 31,	
	2007	2006
Proved Developed Oil Reserves (Thousands of Barrels, or MBbls)	623.9	493.3
Proved Undeveloped Oil Reserves (MBbls)	308.1	39.6
Total Proved Oil Reserves (MBbls)	932.0	532.9
Proved Developed Gas Reserves (Million Cubic Feet, or MMcf)	2,455.7	2,399.4
Proved Undeveloped Gas Reserves (MMcf)	240.5	3.0
Total Proved Gas Reserves (MMcf)	2,696.2	2,402.4
Total Proved Gas Equivalents (Million Cubic Feet Equivalent, or MMcfe)(1)	8,287.0	5,598.6
Total Proved Oil Equivalents (Thousands of Barrels Equivalent, or MBOE)(1)	1,381.2	933.0
Present Value of Estimated Future Net Revenues After Income Taxes, Discounted at 10%(3)	$36,194.2	$19,589.8

(1) We converted oil to Mcf of gas equivalent at a ratio of one barrel to six Mcf.

(2) We calculated the present value of estimated future net revenues as of December 31, 2007 and 2006 using oil and natural gas prices that were received by each respective property as of that date. The average realized prices that we utilized for December 31, 2007 and 2006 were $6.97 and $4.53 per Mcf and $81.30 and $50.37 per barrel of oil, respectively.

(3) The Present Value of Estimated Future Net Revenues After Income Taxes, Discounted at 10%, is referred to as the "Standardized Measure." There is no tax effect in 2007 or 2006 as the tax basis in properties and net operating loss exceeds the future net revenues. See Supplemental Oil and Gas Reserve Information (Unaudited) following our audited financial statements for the years ended December 31, 2007 and 2006.

Competition

The oil and gas industry is intensely competitive, particularly with respect to the acquisition of prospective oil and natural gas properties and oil and natural gas reserves. Our ability to effectively compete is dependent on our geological, geophysical and engineering expertise, and our financial resources. We must compete against a substantial number of major and independent oil and natural gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also have refining operations, market refined products and generate electricity. We also compete with other oil and natural gas companies to secure drilling rigs and other equipment necessary for drilling and completion of wells. Consequently, drilling equipment may be in short supply from time to time. Currently, access to additional drilling equipment in certain regions is difficult.

Commodity Price Environment

Generally, the demand for and the price of natural gas increase during the colder winter months and decrease during the warmer summer months. Pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Crude oil and the demand for heating oil are also impacted by seasonal factors, with generally higher prices in the winter. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations.

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. Commodity prices are beyond our control and are difficult to predict. We do not currently hedge any of our production.

The prices received for domestic production of oil and natural gas have increased significantly during the past several years, and are continuing to increase in response to global political issues and domestic shortages, which has resulted in increased demand for the equipment and services that we need to drill, complete and operate wells. As a result of this increased demand for oil field services, shortages have developed, and we have seen an escalation in drilling rig rates, field service costs, material prices and all costs associated with drilling, completing and operating wells. If oil and natural gas prices remain high relative to historical levels, we anticipate that the recent trends toward increasing costs and equipment shortages will continue.

Governmental Regulations and Environmental Laws

Our oil and natural gas exploration, production and related operations, when developed, are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, some states in which we may operate require permits for drilling operations, drilling bonds and reports concerning operations, and impose other requirements relating to the exploration for and production of oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of wells. Failure to comply with any such rules and regulations can result in substantial penalties. The increasing regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Although we believe we are currently in substantial compliance with all applicable laws and regulations, we are unable to predict the future cost or impact of complying with such laws because such rules and regulations are frequently amended or reinterpreted. We may be required to make significant expenditures to comply with governmental laws and regulations, which could have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to various types of regulation at the federal, state, tribal and local levels that:

- require certain permits for the drilling of wells, including permits to drill wells on federal lands as well as lands administered by the Bureau of Indian Affairs, which generally require a minimum of 60-120 days; and permits to drill wells on state and fee lands, which generally require a minimum of 30-60 days;
- mandate that we maintain bonding requirements in order to drill or operate wells; and
- regulate the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, temporary storage tank operations, air emissions from flaring, compression, and access roads, sour gas management, and the disposal of fluids used in connection with operations.

Our operations are also subject to various conservation laws and regulations. These regulations govern the size of drilling and spacing units or proration units, the density of wells that may be drilled in oil and natural gas properties, and the unitization or pooling of natural gas and oil properties. In this regard, some states allow the forced pooling or integration of lands and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively voluntary, it may be more difficult to form units and therefore more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities that must be addressed before those activities can proceed. The effect of all these regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Where our operations are located on federal lands, the timing and scope of development may be limited by the National Environmental Policy Act, or environmental or species protection laws and regulations. The regulatory burden on the oil and natural gas industry increases our costs of doing business and, consequently, affects our profitability. Because these laws and regulations are frequently expanded, amended and reinterpreted, we are unable to predict the future cost or impact of complying with applicable environmental and conservation requirements.

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and we expect that this trend will continue. These laws and regulations:

- require the acquisition of permits or other authorizations before construction, drilling and certain other activities;
- limit or prohibit construction, drilling and other activities on specified lands within wilderness and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. We believe that we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us, as well as the oil and natural gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act, or CERCLA, and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum-related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. CERCLA, RCRA and comparable state statutes can impose liability for clean-up of sites and disposal of substances found on drilling and production sites long after operations on such sites have been completed.

The Endangered Species Act, or ESA, seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, or destroy or modify the critical habitat of such species. Under the ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. The ESA has been used to prevent or delay drilling activities and provides for criminal penalties for willful violations of its provisions. Other statutes that provide protection to animal and plant species and that may apply to our operations include, without limitation, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act, the National Historic Preservation Act and often their state, tribal or local counterparts. Projects can be denied or significantly modified to accommodate tribal burial sites, archeological sites or other historical sites. The National Environmental Policy Act, or NEPA, requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal land would result in "significant impact." For purposes of NEPA, "major federal action" can be something as basic as issuance of a required permit. For oil and gas operations on federal lands or requiring federal permits, NEPA review can increase the time for obtaining approval and impose additional regulatory burdens on the natural gas and oil industry, thereby increasing our costs of doing business and our profitability. Although we believe that our operations are in substantial compliance with these statutes, any change in these statutes or any reclassification of a species as threatened or endangered or re-determination of the extent of "critical habit" could subject us to significant expenses to modify our operations or could force us to discontinue some operations altogether. Any new or additional NEPA analysis could also result in significant changes.

The Clean Air Act, as amended, restricts the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. In addition, the EPA has promulgated more stringent regulations governing emissions of toxic air pollutants from sources in the oil and gas industry, and these regulations may increase the costs of compliance for some facilities.

The Company has not incurred, and does not currently anticipate incurring, any material capital expenditures for environmental control facilities.

Employees and Office Space

Our principal executive offices are located at 1625 Broadway, Suite 250, Denver, Colorado 80202, and our telephone number is (303) 592-8075. As of December 31, 2007, we employed fifteen full-time employees. None of our employees are subject to a collective bargaining agreement and we consider our relations with our employees to be excellent.

Available Information

We maintain a website at http://www.kodiakog.com. The information contained on or accessible through our website is not part of this 10-K. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, and amendments to reports filed or furnished pursuant to Sections 13(a) and 15(d) of the Securities Exchange Act of 1934, as amended, are available on our website as soon as reasonably practicable after we electronically file such reports with, or furnish those reports to, the Securities and Exchange Commission.

We maintain a code of ethics applicable to our Board of Directors, officers and employees. A copy of our Code of Business Conduct and Ethics for Directors, Officers and Employees may be found on our website in the Corporate Governance section. This document contains information regarding whistleblower procedures.

ITEM 1A. RISK FACTORS

Investing in shares of our common stock is highly speculative and involves a high degree of risk. In addition to the other information included in this Form 10-K, you should carefully consider the risks described below before purchasing shares of our common stock. If any of the following risks actually occur, our business, financial condition and results of operations could materially suffer. As a result, the trading price of our common stock could decline, and you might lose all or part of your investment.

Risks Relating to the Company

We will require significant additional capital, which may not be available to us on favorable terms, or at all.

Our working capital decreased from $51.2 million as of December 31, 2006, to $10.2 million as of December 31, 2007. Future acquisitions and future exploration, development and production activities will require a substantial amount of additional working capital and cash flow. Our plan of operations for 2008 contemplates capital expenditures of $12.6 million for the development of existing properties and anticipated property acquisitions. The 2008 estimated capital expenditures do not include the amount that Devon is required to spend under the Devon Agreement or the proceeds of anticipated divestitures. We expect that our current cash balances and cash flow from operations will be sufficient only to provide a limited amount of working capital, and the anticipated revenues generated from our properties will not alone be sufficient to fund our operations or planned growth. As a result, we will need to seek alternative sources of capital, by either entering into joint ventures with other exploration and production companies or by undertaking financing activities. In addition, we expect that we will need to raise additional funds in the future in order to fund our plan of operation beyond 2008, which may not be available in amounts or on terms acceptable to us, if at all.

If we borrow additional funds, we will likely be obligated to make periodic interest or other debt service payments and may be subject to additional restrictive covenants. The ability to borrow additional funds is dependent on a number of variables, including our proved reserves, and assumptions regarding the price at which oil and natural gas can be sold. Should we elect to raise additional capital through the issuance and sale of equity securities, the sales may be at prices below the market price of our stock, and our shareholders may suffer significant dilution. Our failure to obtain financing on a timely basis or on favorable terms could result in the loss or substantial dilution of our interests in our properties as disclosed in this Form 10-K. In addition, the failure of any of us or our joint venture partners to obtain any required financing could adversely affect our ability to complete the exploration or development of any of our joint venture projects on a timely basis. This could result in the curtailment of operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas and oil reserves.

We have historically incurred losses and expect to incur additional losses in the future. It is difficult for us to forecast when we will achieve profitability, if ever.

We have historically incurred losses from operations during our history in the oil and natural gas business. As of December 31, 2007, we had a cumulative deficit of $46.8 million. While we have developed some of our properties, most of our properties are in the exploration stage and to date we have established a limited volume of proved reserves on our properties. To become profitable, we would need to be successful in our acquisition, exploration, development and production activities, all of which are subject to many risks beyond our control. We cannot assure you that we will successfully implement our business plan or that we will achieve commercial profitability in the future. Even if we become profitable, we cannot assure you that our profitability will be sustainable or increase on a periodic basis. In addition, should we be unable to continue as a going concern, realization of assets and settlement of liabilities in other than the normal course of business may be at amounts significantly different from those in the financial statements included in this Form 10-K. Finally, due to our limited history in the oil and natural gas business, we have limited historical financial and operating information available to help you evaluate our performance or an investment in our common stock.

We may not be able to successfully drill wells that can produce oil or natural gas in commercially viable quantities.

We cannot assure you that we will be able to successfully drill wells that can produce commercial quantities of oil and natural gas in the future. The total cost of drilling, completing and operating a well is uncertain before drilling commences. Overruns in budgeted expenditures is a common risk that can make a particular project uneconomical. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. Our use of seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil. Further, many factors may curtail, delay or cancel drilling, including the following:

- our limited history of drilling wells;
- delays and restrictions imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- land title problems; and
- limitations in the market for oil and natural gas.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. The occurrence of any of these events could negatively affect our ability to successfully drill wells that can produce oil or natural gas in commercially viable quantities.

While our management team has considerable industry experience, we have limited experience as a company as an operator of wells. If we fail to successfully manage our drilling and exploration programs or fail to successfully operate our wells, we may not obtain sufficient revenues to earn a profit. From 2005 through December 31, 2007, we participated in drilling a total of 33 gross wells, of which 24 were completed as producing, seven were identified as dry holes, and two are waiting on completion. If we drill a disproportionate number of additional wells that we identify as dry holes in our current or future prospects, we may materially harm our business.

Our focus on exploration activities exposes us to greater risks than are generally encountered in later-stage oil and natural gas property development businesses.

Much of our current activity involves drilling exploratory wells on properties with no proved oil and natural gas reserves. While all drilling, whether developmental or exploratory, involves risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of oil and natural gas. The economic success of any project will depend on numerous factors, including:

- our ability to drill, complete and operate wells;

- our ability to estimate the volumes of recoverable reserves relating to individual projects;
- rates of future production;
- future commodity prices; and
- investment and operating costs and possible environmental liabilities.

All of these factors may impact whether a project will generate cash flows sufficient to provide a suitable return on investment. If we experience a series of failed drilling projects, our business, results of operations and financial condition could be materially adversely affected.

The actual quantities and present value of our proved reserves may be lower than we have estimated.

This Form 10-K contains estimates of our proved oil and natural gas reserves and the estimated future net revenues from these reserves. The December 31, 2007 reserve estimate was prepared by us and audited by Netherland Sewell and Associates. The process of estimating oil and natural gas reserves is complex and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Accordingly, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development and operating expenses, and quantities of recoverable oil and natural gas reserves most likely will vary from these estimates and vary over time. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, results of secondary and tertiary recovery applications, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues referred to in this Form 10-K is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any change in consumption by oil or natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of our oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor nor does it reflect discount factors used in the market place for the purchase and sale of oil and natural gas.

The imprecise nature of estimating proved natural gas and oil reserves, future downward revisions of proved reserves and increased drilling expenditures without current additions to proved reserves may lead to write downs in the carrying value of our natural gas and oil properties.

Due to the imprecise nature of estimating natural gas and oil reserves as well as the potential volatility in natural gas and oil prices and their effect on the carrying value of our natural gas and oil properties, write downs in the future may be required as a result of factors that may negatively affect the present value of proved natural gas and oil reserves. These factors can include volatile natural gas and oil prices, downward revisions in estimated proved natural gas and oil reserve quantities, limited classification of proved reserves associated with successful wells and unsuccessful drilling activities.

Our reserves and production will decline and unless we replace our oil and natural gas reserves, our business, financial condition and results of operations will be adversely affected.

Producing oil and natural gas reserves ultimately results in declining production that will vary depending on reservoir characteristics and other factors. Thus, our future oil and natural gas production and resulting cash flow and earnings are directly dependent upon our success in developing our current reserves and finding additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

We have not insured and cannot fully insure against all risks related to our operations, which could result in substantial claims for which we are underinsured or uninsured.

We have not insured and cannot fully insure against all risks and have not attempted to insure fully against risks where coverage is prohibitively expensive. We do not carry business interruption insurance coverage. Our exploration, drilling and other activities are subject to risks such as:

- fires and explosions;
- environmental hazards, such as uncontrollable flows of natural gas, oil, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical failures of drilling equipment;
- personal injuries and death, including insufficient worker compensation coverage for third-party contractors who provide drilling services; and
- natural disasters, such as adverse weather conditions.

Losses and liabilities arising from uninsured and underinsured events, which could arise from even one catastrophic accident, could materially and adversely affect our business, results of operations and financial condition.

We have limited control over activities in properties we do not operate, which could reduce our production and revenues and affect the timing and amounts of capital requirements.

We do not operate all of the properties in which we have an interest. As of December 31, 2007, we owned a non-operating interest in seven producing wells in the Vermillion Basin and may acquire non-operating interests in additional wells in the future. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. For all of the properties that are operated by others, we are dependent on their decision-making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator's breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including:

- timing and amount of capital expenditures;
- expertise and financial resources; and
- inclusion of other participants.

In the first quarter of 2008, we entered into an exploration and development agreement which, among other terms, provides that our partner will be the operator of record for future wells. We will continue to have input and involvement in the timing, location, and design of the operations but our overall control of these activities will be reduced.

Our operations in North Dakota, Montana and Wyoming could be adversely affected by abnormally poor weather conditions.

Our operations in North Dakota, Montana and Wyoming are conducted in areas subject to extreme weather conditions and often in difficult terrain. Primarily in the winter and spring, our operations are often curtailed because of cold, snow and wet conditions. Unusually severe weather could further curtail these operations, including drilling of new wells or production from existing wells, and depending on the severity of the weather, could have a material adverse effect on our business, financial condition and results of operations.

In addition, our federal leases generally include restrictions on drilling during the period of November 15 to April 30. These restrictions are intended to protect big game winter habitat and not to restrict operations or maintenance of production facilities. To the extent that our exploration and drilling program on our federal leases cannot be completed during the period of May 1 through November 14, our drilling program may be delayed.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

We deliver oil and natural gas through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder access to oil and natural gas markets or delay production, if any, at our wells. The availability of a ready market for our future oil and natural gas production will depend on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Any significant change in our arrangements with gathering system or pipeline owners and operators or other market factors affecting the overall infrastructure facilities servicing our properties would adversely affect our ability to deliver the oil and natural gas we produce to markets in an efficient manner.

Pipeline capacity in the Rocky Mountain region may be inadequate, and consequently, a price decrease may be more likely to affect the price received for our Rocky Mountain production more than production in other U.S. regions.

Natural gas prices are critical to our business, and the marketability of our production will depend on the capacity of oil and natural gas gathering systems and pipelines. Oftentimes, the market price for natural gas in the Rocky Mountain region differs from the market indices for natural gas in other regions of the United States. Therefore, a price decrease may more adversely affect the price received for our Rocky Mountain production than production in the other U.S. regions. From time to time, new pipeline projects have been announced or built to transport natural gas production from the Rocky Mountain region to other markets. For example, in early 2008 the Rockies Express Pipeline, or REX, began operations and is transporting gas to the Midwest United States market and in 2009 will be extended to Eastern U.S. markets. However, there can be no assurance that REX or other future infrastructure will be sufficient to prevent large basis differentials from occurring in the future. The unavailability or insufficient capacity of pipeline facilities could force us to shut-in producing wells, delay the commencement of production, or discontinue development plans for some of our properties, which would adversely affect our financial condition and performance.

During the second half of 2007, basis differential between the natural gas prices in the Rocky Mountain region and the New York Mercantile Exchange, or NYMEX, settlement prices were disproportionately larger than that for other markets. We believe that this was due in part to constraints in transporting natural gas from the Rocky Mountain region to consuming markets. As a result, we chose to shut in our natural gas production during the late summer and fall of 2007. Because of our concentration of operations in the Rocky Mountain region, future differentials will have a larger affect on our natural gas revenue than that of other geographically diverse producers.

We rely on independent experts and technical or operational service providers over whom we may have limited control.

We use independent contractors to provide us with technical assistance and services. We rely upon the owners and operators of rigs and drilling equipment, and upon providers of field services, to drill and develop our prospects to production. In addition, we rely upon the services of other third parties to explore or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. Our limited control over the activities and business practices of these providers, any inability on our part to maintain satisfactory commercial relationships with them or their failure to provide quality services could materially and adversely affect our business, results of operations and financial condition.

Our interests are held in the form of leases that we may be unable to retain and the title to our properties may be defective.

Our properties are held under leases, and working interests in leases. Generally, the leases we are a party to are for a fixed term, but contain a provision that allows us to extend the term of the lease so long as we are producing oil or natural gas in quantities to meet the required payments under the lease. If we or the holder of a lease fails to meet the specific requirements of the lease regarding delay rental payments, continuous production or development, or similar terms, portions of the lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each lease will be met. The termination or expiration of our leases or the working interests relating to leases may reduce our opportunity to exploit a given prospect for oil and natural gas production and thus have a material adverse effect on our business, results of operation and financial condition.

It is our practice in acquiring oil and natural gas leases or interests in oil and natural gas leases not to undergo the expense of retaining lawyers to fully examine the title to the interest to be placed under lease or already placed under lease. Rather, we rely upon the judgment of oil and natural gas lease brokers or landmen who actually do the field work in examining records in the appropriate governmental office before attempting to place under lease a specific interest. We believe that this practice is widely followed in the oil and natural gas industry.

Prior to drilling a well for oil and natural gas, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to hire a lawyer to examine the title to the unit within which the proposed oil and natural gas well is to be drilled. Frequently, as a result of such examination, curative work must be done to correct deficiencies in the marketability of the title. The work entails expense and might include obtaining an affidavit of heirship or causing an estate to be administered. The examination made by the title lawyers may reveal that the oil and natural gas lease or leases are worthless, having been purchased in error from a person who is not the owner of the mineral interest desired. In such instances, the amount paid for such oil and natural gas lease or leases may be lost.

Properties that we acquire may not produce oil or natural gas as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses.

One of our growth strategies is to pursue selective acquisitions of oil and natural gas reserves. If we choose to pursue an acquisition, we will perform a review of the target properties that we believe is consistent with industry practices. However, these reviews are inherently incomplete. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. We may not perform an inspection on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may not be able to obtain effective contractual protection against all or part of those problems, and we may assume environmental and other risks and liabilities in connection with the acquired properties.

Our officers and directors may become subject to conflicts of interest.

Some of our directors and officers may also become directors, officers, contractors, shareholders or employees of other companies engaged in oil and natural gas exploration and development. To the extent that such other companies may participate in ventures in which we may participate, our directors may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation. In the event that such a conflict of interest arises at a meeting of our directors, a director who has such a conflict will declare his interest and abstain from voting for or against the approval of such participation or such terms. In appropriate cases, we will establish a special committee of independent directors to review a matter in which several directors, or management, may have a conflict. From time to time, several companies may participate in the acquisition, exploration and development of oil and natural gas properties thereby allowing for their participation in larger programs, permitting involvement in a greater number of programs and reducing financial exposure in respect of any one program. A particular company may assign all or a portion of its interest in a particular program to another of these companies due to the financial position of the company making the assignment.

In accordance with the laws of the Yukon Territory, our directors are required to act honestly, in good faith and in the best interests of our company. In determining whether or not we will participate or acquire an interest in a particular program, our officers will primarily consider the potential benefits to our company, the degree of risk to which we may be exposed and our financial position at the time. See "Related Party Transactions."

We depend on a number of key personnel who would be difficult to replace.

We are dependent upon the expertise of our management team, including our executive officers and other key employees. Although we have obtained "key man" insurance for our Chief Executive Officer and Chief Operating Officer, the loss of the services of our executive officers, or any other member of our management team, through incapacity or otherwise, would be costly to us and would require us to seek and retain other qualified personnel. We have entered into employment agreements with Messrs. Peterson, Catlin and Henderson that contain non-compete agreements. Notwithstanding these agreements, we may not be able to retain our executive officers and may not be able to enforce all of the provisions in the employment agreements. Failure to find suitable replacement for any member of our management team could negatively impact our ability to execute our strategy.

We have made and will continue to make substantial financial and man-power investments in order to assess and maintain our internal controls over financial reporting and our internal controls over financial reporting may be found to be deficient.

Section 404 of the Sarbanes-Oxley Act of 2002 requires management to assess our internal controls over financial reporting and requires our auditors to express an opinion on those controls. The auditors conducted their audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that the auditors plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Current regulations of the Securities and Exchange Commission, or SEC, requires us to include this assessment and opinion in this annual report for our fiscal year ended December 31, 2007.

We have incurred and will continue to incur significant increased costs in implementing and adhering to these requirements. In particular, the rules governing the standards that must be met for management to assess its internal controls over financial reporting under Section 404 are complex, and require significant documentation, testing and possible remediation. Our process of reviewing, documenting and testing our internal controls over financial reporting may cause a significant strain on our management, information systems and resources. We have invested in and may continue to invest in additional accounting and software systems. We have hired and continue to retain additional personnel and to use outside legal, accounting and advisory services. In addition, we have incurred additional fees from our auditors as they perform the additional services necessary for them to provide their attestation. If we are unable to favorably assess and continue to maintain the effectiveness of our internal control over financial reporting when we are required to, or if our independent auditors are unable to provide an unqualified attestation report on such assessment, we may be required to change our internal control over financial reporting to remediate deficiencies. In addition, investors may lose confidence in the reliability of our financial statements causing our stock price to decline.

Risks Relating to Our Industry

The oil and natural gas industry is subject to significant competition, which may increase costs or otherwise adversely affect our ability to compete.

Oil and natural gas exploration is intensely competitive and involves a high degree of risk. In our efforts to acquire oil and natural gas producing properties, we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also conduct refining and petroleum marketing operations on a worldwide basis. Our ability to compete for oil and natural gas producing properties will be affected by the amount of funds available to us, information available to us and any standards established by us for the minimum projected return on investment. Our products will also face competition from alternative fuel sources and technologies.

Oil and natural gas are commodities subject to price volatility based on many factors outside the control of producers, and low prices may make properties uneconomic for future production.

Oil and natural gas are commodities, and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices a producer may expect and its level of production depend on numerous factors beyond its control, such as:

- changes in global supply and demand for oil and natural gas;
- economic conditions in the United States and Canada;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- government regulation;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in oil- and natural gas-producing regions;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and

- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease revenues on a per unit basis, but also may reduce the amount of oil and natural gas that can be economically produced. Lower prices will also negatively affect the value of proved reserves.

Exploration and drilling operations are subject to significant environmental regulation, which may increase costs or limit our ability to develop our properties.

We may encounter hazards incident to the exploration and development of oil and natural gas properties such as accidental spills or leakage of petroleum liquids and other unforeseen conditions. We may be subject to liability for pollution and other damages due to hazards that we cannot insure against due to prohibitive premium costs or for other reasons. Governmental regulations relating to environmental matters could also increase the cost of doing business or require alteration or cessation of operations in some areas.

Existing and possible future environmental legislation, regulations and actions could give rise to additional expense, capital expenditures, restrictions and delays in our activities, the extent of which we cannot predict. Regulatory requirements and environmental standards are subject to constant evaluation and may be significantly increased, which could materially and adversely affect our business or our ability to develop our properties on an economically feasible basis. Before development and production can commence on any properties, we must obtain regulatory and environmental approvals. We cannot assure you that we will obtain such approvals on a timely basis or at all. The cost of compliance with changes in governmental regulations has the potential to reduce the profitability of our operations and preclude entirely the economic development of a specific property.

A substantial or extended decline in oil and natural gas prices could reduce our future revenue and earnings.

As with most other companies involved in resource exploration and development, we may be adversely affected by future increases in the costs of conducting exploration, development and resource extraction that may not be fully offset by increases in the price received on sale of oil or natural gas.

Our revenues and growth, and the carrying value of our oil and natural gas properties are substantially dependent on prevailing prices of oil and natural gas. Our ability to obtain additional capital on attractive terms is also substantially dependent upon 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 of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include changes in global supply and demand for oil and natural gas, economic conditions in the United States and Canada, the actions of OPEC, governmental regulation, the price and quantity of imports in foreign oil and natural gas-producing regions, political conditions, including embargoes in oil and natural gas-producing regions, the level of global oil and natural gas inventories, weather conditions, technological advances affecting energy consumption and the price and availability of alternate fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on our business, financial condition and results of operations.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Local, national and international economic conditions are beyond our control and may have a substantial adverse effect on our efforts. We cannot guard against the effects of these potential adverse conditions.

Our operations and demand for our products are affected by seasonal factors, which may lead to fluctuations in our operating results.

Our operating results are likely to vary due to seasonal factors. Demand for oil and natural gas products will generally increase during the winter because they are often used as heating fuels. The amount of such increased demand will depend to some extent upon the severity of winter. Because of the seasonality of our business and continuous fluctuations in the prices of our products, our operating results are likely to fluctuate from period to period.

Conducting operations in the oil and natural gas industry subjects us to complex laws and regulations that can have a material adverse effect on the cost, manner and feasibility of doing business.

Companies that explore for and develop, produce and sell oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of operations and subject us to liabilities under administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our cost of operations or our ability to execute our plans on a timely basis.

Due to domestic drilling activity increases, particularly in fields in which we operate, a general shortage of drilling rigs, equipment, supplies and personnel has developed. As a result, the costs and delivery times of rigs, equipment, supplies or personnel are substantially greater than in previous years. From time to time, these costs have sharply increased and could do so again. The demand for and wage rates of qualified drilling rig crews generally rise in response to the increasing number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development operations, which could have a material adverse effect on our business, financial condition and results of operations.

Risks Relating to Our Common Stock

Our common stock has a limited trading history and has experienced price volatility.

Our common stock has been trading on the American Stock Exchange, or AMEX, since June 21, 2006. Prior to listing on AMEX our common stock traded on the TSX Venture Exchange, or TSX-V, beginning September 28, 2001. The volume of trading in our common stock varies greatly and may often be light, resulting in what is known as a "thinly-traded" stock. Until a larger secondary market for our common stock develops, the price of our common stock may fluctuate substantially. The price of our common stock may also be impacted by any of the following, some of which may have little or no relation to our company or industry:

- the breadth of our stockholder base and extent to which securities professionals follow our common stock;
- investor perception of our Company and the oil and natural gas industry, including industry trends;
- domestic and international economic and capital market conditions, including fluctuations in commodity prices;
- responses to quarter-to-quarter variations in our results of operations;
- announcements of significant acquisitions, strategic alliances, joint ventures or capital commitments by us or our competitors;
- additions or departures of key personnel;
- sales or purchases of our common stock by large stockholders or our insiders;
- accounting pronouncements or changes in accounting rules that affect our financial reporting; and
- changes in legal and regulatory compliance unrelated to our performance.

In addition, the stock market in general and the market for natural gas and oil exploration companies in particular have experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating results or asset values of those companies. These broad market and industry factors may seriously impact the market price and trading volume of our common shares regardless of our actual operating performance.

We have not paid cash dividends on our common stock and do not anticipate paying any dividends on our common stock in the foreseeable future.

We do not anticipate paying cash dividends on our common stock in the foreseeable future. Payment of future cash dividends, if any, will be at the discretion of our board of directors and will depend on our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors that our board of directors considers relevant. Accordingly, investors may only see a return on their investment if the value of our securities appreciates.

Our constating documents permit us to issue an unlimited number of shares without shareholder approval.

Our Articles of Continuation permit us to issue an unlimited number of shares of our common stock. Subject to the requirements of any exchange on which we may be listed, we will not be required to obtain the approval of shareholders for the issuance of additional shares of our common stock. In 2005, we issued 20,671,875 shares of our common stock for net proceeds of $17,879,673. In 2006, we issued 31,589,268 shares of our common stock for net proceeds of $83,209,451. We anticipate that we will, from time to time, issue additional shares of our common stock to provide working capital for future operations. Any further issuances of shares of our common stock from our treasury will result in immediate dilution to existing shareholders and may have an adverse effect on the value of their shareholdings.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 3. LEGAL PROCEEDINGS

We have no material legal proceedings pending, and we do not know of any material proceedings contemplated by governmental authorities. There are no material proceedings to which any director, officer or any of our affiliates, any owner of record or beneficially of more than five percent of any class of our voting securities, or any associate of any such director, officer, our affiliates, or security holder, is a party adverse to us or our consolidated subsidiary or has a material interest adverse to us or our consolidated subsidiary.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not Applicable.

PART II

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

Market Information

Shares of our common stock, no par value, are issued in registered form. The transfer agent for the shares is Computershare Trust Company Inc., 100 University Avenue, 9th Floor, Toronto, Ontario M5J 2Y1. Our common stock has been listed and posted for trading on the AMEX since June 21, 2006 under the symbol "KOG". On February 28, 2008, there were 83 holders of record of our Common Stock which does not include the shareholders for whom shares are held in a nominee or street name.

High and Low Prices for Each Quarter in the Last Two Fiscal Years

	AMEX	
Period Ended	**High**	**Low**
December 31, 2007	$3.49	$1.64
September 30, 2007	$5.38	$3.30
June 30, 2007	$6.58	$4.82
March 31, 2007	$5.52	$3.68
December 31, 2006	$4.60	$3.08
September 30, 2006	$4.65	$3.17
June 30, 2006	$4.06	$3.32

Dividend Policy

We have never paid any cash dividends on our common stock and do not anticipate paying any dividends in the foreseeable future. Our current business plan is to retain any future earnings to finance the expansion and development of our business. Any future determination to pay cash dividends will be at the discretion of our board of directors, and will be dependent upon our financial condition, results of operations, capital requirements and other factors as our board may deem relevant at that time.

Securities Authorized for Issuance under Equity Compensation Plans

In 2007 we adopted the 2007 Stock Incentive Plan (the "2007 Plan"), which replaced the Incentive Share Option Plan (the "Pre-existing Plan"). Under the 2007 Plan, stock options, stock appreciation rights (SARs), restricted stock and restricted stock units, performance awards, stock or property, stock awards and other stock-based awards may be granted to any employee, consultant, independent contractor, director or officer of the Company. A total of 8,000,000 shares of common stock may be issued under the 2007 Plan, which includes shares issuable under the Pre-existing Plan pursuant to options outstanding as of the effective date of the 2007 Plan. No more than 8,000,000 shares may be used for stock issued pursuant to incentive stock options and the number of shares available for granting restricted stock and restricted stock units shall not exceed 1,000,000, subject to adjustment as defined in the 2007 Plan. We granted 2,044,000 stock options and 81,000 shares of restricted stock in 2007. As of February 28, 2008, the Company has outstanding options to purchase 6,112,000 common shares at prices ranging from $0.45 to $6.26.

Equity Compensation Plan Information as of December 31, 2007

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders .	6,112,000(1)	$3.25	1,807,000
Equity compensation plans not approved by security holders .	N/A	N/A	N/A
Total	6,112,000(1)	$3.25	1,807,000

(1) Excludes 81,000 shares of restricted stock granted in 2007.

Exchange Controls

Canada has no system of exchange controls. There are no exchange restrictions on borrowing from foreign countries nor on the remittance of dividends, interest, royalties and similar payments, management fees, loan repayments, settlement of trade debts, or the repatriation of capital. However, any dividends remitted to U.S. Holders, as defined below, will be subject to withholding tax. See "Canadian Federal Income Tax Considerations."

Except as provided in the Investment Canada Act (the "Act"), as amended by the Canada-United States Free Trade Implementation Act (Canada) and the Canada-United States Free Trade Agreement, there are no limitations specific to the rights of non-Canadians to hold or vote our common stock under the laws of Canada or the Yukon Territory or in our charter documents. Our company is not a "Canadian business," as defined in the Act; therefore, the limitations in the Act do not apply to our company.

Material Income Tax Consequences

A brief description of certain provisions of the tax treaty between Canada and the United States is included below, together with a brief outline of certain taxes, including withholding provisions, to which United States security holders are subject under existing laws and regulations of Canada and the United States. The consequences, if any, of provincial, state and local taxes are not considered.

The following information is general and security holders should seek the advice of their own tax advisors, tax counsel or accountants with respect to the applicability or effect on their own individual circumstances of the matters referred to herein and of any provincial, state or local taxes.

U.S. Federal Income Tax Consequences

The following is a summary of certain material U.S. federal income tax consequences to a U.S. Holder (as defined below) arising from and relating to the acquisition, ownership, and disposition of common shares of the Company ("Common Shares").

This summary is for general information purposes only and does not purport to be a complete analysis or listing of all potential U.S. federal income tax consequences that may apply to a U.S. Holder as a result of the acquisition, ownership, and disposition of Common Shares. In addition, this summary does not take into account the individual facts and circumstances of any particular U.S. Holder that may affect the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares. Accordingly, this summary is not intended to be, and should not be construed as, legal or U.S. federal income tax advice with respect to any U.S. Holder. Each U.S. Holder should consult its own tax advisor regarding the U.S. federal income, U.S. state and local, and foreign tax consequences of the acquisition, ownership, and disposition of Common Shares.

Scope of this Summary

Authorities

This summary is based on the Internal Revenue Code of 1986, as amended (the "Code"), Treasury Regulations (whether final, temporary, or proposed), published rulings of the Internal Revenue Service (the "IRS"), published administrative positions of the IRS, the Convention Between Canada and the United States of America with Respect to Taxes on Income and on Capital, signed September 26, 1980, as amended (the "Canada-U.S. Tax Convention"), and U.S. court decisions that are applicable and, in each case, as in effect and available, as of the date of this Form 10-K. Any of the authorities on which this summary is based could be changed in a material and adverse manner at any time, and any such change could be applied on a retroactive basis. This summary does not discuss the potential effects, whether adverse or beneficial, of any proposed legislation that, if enacted, could be applied on a retroactive basis.

U.S. Holders

For purposes of this summary, a "U.S. Holder" is a beneficial owner of Common Shares that, for U.S. federal income tax purposes, is (a) an individual who is a citizen or resident of the U.S., (b) a corporation, or any other entity classified as a corporation for U.S. federal income tax purposes, that is created or organized in or under the laws of the U.S., any state in the U.S., or the District of Columbia, (c) an estate if the income of such estate is subject to U.S. federal income tax regardless of the source of such income, or (d) a trust if (i) such trust has validly elected to be treated as a U.S. person for U.S. federal income tax purposes or (ii) a U.S. court is able to exercise primary supervision over the administration of such trust and one or more U.S. persons have the authority to control all substantial decisions of such trust.

Non-U.S. Holders

For purposes of this summary, a "non-U.S. Holder" is a beneficial owner of Common Shares other than a U.S. Holder. This summary does not address the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares to non-U.S. Holders. Accordingly, a non-U.S. Holder should consult its own tax advisor regarding the U.S. federal income, U.S. state and local, and foreign tax consequences (including the potential application of and operation of any income tax treaties) of the acquisition, ownership, and disposition of Common Shares.

U.S. Holders Subject to Special U.S. Federal Income Tax Rules Not Addressed

This summary does not address the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares to U.S. Holders that are subject to special provisions under the Code, including the following U.S. Holders: (a) U.S. Holders that are tax-exempt organizations, qualified retirement plans, individual retirement accounts, or other tax-deferred accounts; (b) U.S. Holders that are financial institutions, insurance companies, real estate investment trusts, or regulated investment companies; (c) U.S. Holders that are dealers in securities or currencies or U.S. Holders that are traders in securities that elect to apply a mark-to-market accounting method; (d) U.S. Holders that have a "functional currency" other than the U.S. dollar; (e) U.S. Holders that are liable for the alternative minimum tax under the Code; (f) U.S. Holders that own Common Shares as part of a straddle, hedging transaction, conversion transaction, constructive sale, or other arrangement involving more than one position; (g) U.S. Holders that acquired Common Shares in connection with the exercise of employee stock options or otherwise as compensation for services; (h) U.S. Holders that hold Common Shares other than as a capital asset within the meaning of Section 1221 of the Code; or (i) U.S. Holders that own (directly, indirectly, or constructively) 10% or more of the total combined voting power of all classes of shares of the Company entitled to vote. U.S. Holders that are subject to special provisions under the Code, including U.S. Holders described immediately above, should consult their own tax advisors regarding the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares.

If an entity that is classified as a partnership for U.S. federal income tax purposes holds Common Shares, the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares to such partnership and the partners of such partnership generally will depend on the activities of the partnership and the status of such partners. Partners of entities that are classified as partnerships for U.S. federal income tax purposes should consult their own tax advisors regarding the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares.

Tax Consequences Other than U.S. Federal Income Tax Consequences Not Addressed

This summary does not address the U.S. state and local, U.S. federal estate and gift, or foreign tax consequences to U.S. Holders of the acquisition, ownership, and disposition of Common Shares. Each U.S. Holder should consult its own tax advisor regarding the U.S. state and local, U.S. federal estate and gift, and foreign tax consequences of the acquisition, ownership, and disposition of Common Shares.

U.S. Federal Income Tax Consequences of the Acquisition, Ownership, and Disposition of Common Shares

Distributions on Common Shares

General Taxation of Distributions

Subject to the "passive foreign investment company" rules discussed below, a U.S. Holder that receives a distribution, including a constructive distribution, with respect to the Common Shares will be required to include the amount of such distribution in gross income as a dividend (without reduction for any Canadian income tax withheld from such distribution) to the extent of the current or accumulated "earnings and profits" of the Company, as determined for U.S. federal income tax purposes. To the extent that a distribution exceeds the current and accumulated "earnings and profits" of the Company, such distribution will be treated (a) first, as a tax-free return of capital to the extent of a U.S. Holder's tax basis in the Common Shares and, (b) thereafter, as gain from the sale or exchange of such Common Shares. (See more detailed discussion at "Disposition of Common Shares" below).

Reduced Tax Rates for Certain Dividends

For taxable years beginning before January 1, 2011, a dividend paid by the Company generally will be taxed at the preferential tax rates applicable to long-term capital gains if (a) the Company is a "qualified foreign corporation" (as defined below), (b) the U.S. Holder receiving such dividend is an individual, estate, or trust, and (c) such dividend is paid on Common Shares that have been held by such U.S. Holder for at least 61 days during the 121-day period beginning 60 days before the "ex-dividend date."

The Company generally will be a "qualified foreign corporation" under Section 1(h)(11) of the Code (a "QFC") if (a) the Company is eligible for the benefits of the Canada-U.S. Tax Convention, or (b) the Common Shares are readily tradable on an established securities market in the U.S. However, even if the Company satisfies one or more of such requirements, the Company will not be treated as a QFC if the Company is a "passive foreign investment company" (as defined below) for the taxable year during which the Company pays a dividend or for the preceding taxable year.

As discussed below, the Company does not believe that it was a "passive foreign investment company" for the taxable year ended 2007, and based on current business plans and financial projections, the Company does not expect that it will be a "passive foreign investment company" for the taxable year ending 2008. (See more detailed discussion at "Additional Rules that May Apply to U.S. Holders" below). However, there can be no assurance that the IRS will not challenge the determination made by the Company concerning its "passive foreign investment company" status or that the Company will not be a "passive foreign investment company" for the current taxable year or any subsequent taxable year. Accordingly, although the Company expects that it may be a QFC for the taxable year ending 2007, there can be no assurances that the IRS will not challenge the determination made by the Company concerning its QFC status, that the Company will be a QFC for the taxable year ending 2007 or any subsequent taxable year, or that the Company will be able to certify that it is a QFC in accordance with the certification procedures issued by the Treasury and the IRS.

If the Company is not a QFC, a dividend paid by the Company to a U.S. Holder, including a U.S. Holder that is an individual, estate, or trust, generally will be taxed at ordinary income tax rates (and not at the preferential tax rates applicable to long-term capital gains). The dividend rules are complex, and each U.S. Holder should consult its own tax advisor regarding the dividend rules.

Distributions Paid in Foreign Currency

The amount of a distribution received on the Common Shares in foreign currency generally will be equal to the U.S. dollar value of such distribution based on the exchange rate applicable on the date of receipt. A U.S. Holder that does not convert foreign currency received as a distribution into U.S. dollars on the date of receipt generally will have a tax basis in such foreign currency equal to the U.S. dollar value of such foreign currency on the date of receipt. Such a U.S. Holder generally will recognize ordinary income or loss on the subsequent sale or other taxable disposition of such foreign currency (including an exchange for U.S. dollars).

Dividends Received Deduction

Dividends received on the Common Shares generally will not be eligible for the "dividends received deduction." The availability of the dividends received deduction is subject to complex limitations that are beyond the scope of this summary, and a U.S. Holder that is a corporation should consult its own tax advisor regarding the dividends received deduction.

Disposition of Common Shares

A U.S. Holder will recognize gain or loss on the sale or other taxable disposition of Common Shares in an amount equal to the difference, if any, between (a) the amount of cash plus the fair market value of any property received and (b) such U.S. Holder's tax basis in the Common Shares sold or otherwise disposed of. Subject to the "passive foreign investment company" rules discussed below, any such gain or loss generally will be capital gain or loss, which will be long-term capital gain or loss if the Common Shares are held for more than one year.

Preferential tax rates apply to long-term capital gains of a U.S. Holder that is an individual, estate, or trust. There are currently no preferential tax rates for long-term capital gains of a U.S. Holder that is a corporation. Deductions for capital losses are subject to significant limitations under the Code.

Foreign Tax Credit

A U.S. Holder that pays (whether directly or through withholding) Canadian income tax with respect to dividends received on the Common Shares generally will be entitled, at the election of such U.S. Holder, to receive either a deduction or a credit for such Canadian income tax paid. Generally, a credit will reduce a U.S. Holder's U.S. federal income tax liability on a dollar-for-dollar basis, whereas a deduction will reduce a U.S. Holder's income subject to U.S. federal income tax. This election is made on a year-by-year basis and applies to all foreign taxes paid (whether directly or through withholding) by a U.S. Holder during a taxable year.

Complex limitations apply to the foreign tax credit, including the general limitation that the credit cannot exceed the proportionate share of a U.S. Holder's U.S. federal income tax liability that such U.S. Holder's "foreign source" taxable income bears to such U.S. Holder's worldwide taxable income. In applying this limitation, a U.S. Holder's various items of income and deduction must be classified, under complex rules, as either "foreign source" or "U.S. source." In addition, this limitation is calculated separately with respect to specific categories of income. Gain or loss recognized by a U.S. Holder on the sale or other taxable disposition of Common Shares generally will be treated as "U.S. source" for purposes of applying the foreign tax credit rules, unless such gains are resourced as "foreign source" under an applicable income tax treaty, and an election is filed under the Code. Dividends received on the Common Shares generally will be treated as "foreign source" and generally will be categorized as "passive income". The foreign tax credit rules are complex, and each U.S. Holder should consult its own tax advisor regarding the foreign tax credit rules.

Information Reporting; Backup Withholding Tax

Payments made within the U.S., or by a U.S. payor or U.S. middleman, of dividends on, or proceeds arising from the sale or other taxable disposition of, Common Shares generally will be subject to information reporting and backup withholding tax, at the rate of 28%, if a U.S. Holder (a) fails to furnish such U.S. Holder's correct U.S. taxpayer identification number (generally on Form W-9), (b) furnishes an incorrect U.S. taxpayer identification number, (c) is notified by the IRS that such U.S. Holder has previously failed to properly report items subject to backup withholding tax, or (d) fails to certify, under penalty of perjury, that such U.S. Holder has furnished its correct U.S. taxpayer identification number and that the IRS has not notified such U.S. Holder that it is subject to backup withholding tax. However, U.S. Holders that are corporations generally are excluded from these information reporting and backup withholding tax rules. Any amounts withheld under the U.S. backup withholding tax rules will be allowed as a credit against a U.S. Holder's U.S. federal income tax liability, if any, or will be refunded, if such U.S. Holder furnishes required information to the IRS. Each U.S. Holder should consult its own tax advisor regarding the information reporting and backup withholding tax rules.

Additional Rules that May Apply to U.S. Holders

If the Company is a "controlled foreign corporation" or a "passive foreign investment company" (each as defined below), the preceding sections of this summary may not describe the U.S. federal income tax consequences to a U.S. Holder of the acquisition, ownership, and disposition of Common Shares.

Controlled Foreign Corporation

The Company generally will be a "controlled foreign corporation" under Section 957(a) of the Code (a "CFC") if more than 50% of the total voting power or the total value of the outstanding shares of the Company is owned, directly or indirectly, by citizens or residents of the U.S., domestic partnerships, domestic corporations, domestic estates, or domestic trusts (each as defined in

Section 7701(a)(30) of the Code), each of which own, directly or indirectly, 10% or more of the total voting power of the outstanding shares of the Company (a "10% Shareholder").

If the Company is a CFC, a 10% Shareholder generally will be subject to current U.S. federal income tax with respect to (a) such 10% Shareholder's pro rata share of the "subpart F income" (as defined in Section 952 of the Code) of the Company and (b) such 10% Shareholder's pro rata share of the earnings of the Company invested in "United States property" (as defined in Section 956 of the Code). In addition, under Section 1248 of the Code, any gain recognized on the sale or other taxable disposition of Common Shares by a U.S. Holder that was a 10% Shareholder at any time during the five-year period ending with such sale or other taxable disposition generally will be treated as a dividend to the extent of the "earnings and profits" of the Company that are attributable to such Common Shares. If the Company is both a CFC and a "passive foreign investment company" (as defined below), the Company generally will be treated as a CFC (and not as a "passive foreign investment company") with respect to any 10% Shareholder.

The Company does not believe that it has previously been, or currently is, a CFC. However, there can be no assurance that the Company will not be a CFC for the current or any subsequent taxable year.

Passive Foreign Investment Company

The Company generally will be a "passive foreign investment company" under Section 1297(a) of the Code (a "PFIC") if, for a taxable year, (a) 75% or more of the gross income of the Company for such taxable year is passive income or (b) on average, 50% or more of the assets held by the Company either produce passive income or are held for the production of passive income, based on the fair market value of such assets (or on the adjusted tax basis of such assets, if the Company is not publicly traded and either is a "controlled foreign corporation" or makes an election). "Passive income" includes, for example, dividends, interest, certain rents and royalties, certain gains from the sale of stock and securities, and certain gains from commodities transactions. However, for transactions entered into after December 31, 2004, active business gains arising from the sale or exchange of commodities by the Company generally are excluded from "passive income" if substantially all of the Company's commodities are (a) stock in trade of the Company or other property of a kind that would properly be included in inventory of the Company, or property held by the Company primarily for sale to customers in the ordinary course of business, (b) property used in the trade or business of the Company that would be subject to the allowance for depreciation under section 167 of the Code, or (c) supplies of a type regularly used or consumed by the Company in the ordinary course of its trade or business.

For purposes of the PFIC income test and asset test described above, if the Company owns, directly or indirectly, 25% or more of the total value of the outstanding shares of another corporation, the Company will be treated as if it (a) held a proportionate share of the assets of such other corporation and (b) received directly a proportionate share of the income of such other corporation. In addition, for purposes of the PFIC income test and asset test described above, "passive income" does not include any interest, dividends, rents, or royalties that are received or accrued by the Company from a "related person" (as defined in Section 954(d)(3) of the Code), to the extent such items are properly allocable to the income of such related person that is not passive income.

In addition, if the company is a PFIC and owns shares of another foreign corporation that also is a PFIC, under certain indirect ownership rules, a disposition of the shares of such other foreign corporation or a distribution received from such other foreign corporation generally will be treated as an indirect disposition by a U.S. Holder or an indirect distribution received by a U.S. holder, subject to the rules of Section 1291 of the Code discussed below. To the extent that gain recognized on the actual disposition by a U.S. Holder of the company's common stock or income recognized by a U.S. Holder on an actual distribution received on the company's common stock was previously subject to U.S. federal income tax under these indirect ownership rules, such amount generally should not be subject to U.S. federal income tax.

Based on the current composure of the assets and income of the Company, the Company does not believe that it was a PFIC for the taxable year ended 2007, and does not expect that it will be a PFIC for the taxable year ending 2008. The determination of whether the Company was, or will be, a PFIC for a taxable year depends, in part, on the application of complex U.S. federal income tax rules, which are subject to differing interpretations. In addition, whether the Company will be a PFIC for the taxable year ending 2007 and each subsequent taxable year depends on the assets and income of the Company over the course of each such taxable year and, as a result, cannot be predicted with certainty as of the date of this Annual Report. Accordingly, there can be no assurance that the IRS will not challenge the determination made by the Company concerning its PFIC status or that the Company was not, or will not be, a PFIC for any taxable year.

Default PFIC Rules Under Section 1291 of the Code

If the Company is a PFIC, the U.S. federal income tax consequences to a U.S. Holder of the acquisition, ownership, and disposition of Common Shares will depend on whether such U.S. Holder makes an election to treat the Company as a "qualified electing fund" or "QEF" under Section 1295 of the Code (a "QEF Election") or a mark-to-market election under Section 1296 of the Code (a "Mark-to-Market Election"). A U.S. Holder that does not make either a QEF Election or a Mark-to-Market Election will be referred to in this summary as a "Non-Electing U.S. Holder."

A Non-Electing U.S. Holder will be subject to the rules of Section 1291 of the Code with respect to (a) any gain recognized on the sale or other taxable disposition of Common Shares and (b) any excess distribution received on the Common Shares. A distribution generally will be an "excess distribution" to the extent that such distribution (together with all other distributions received in the current taxable year) exceeds 125% of the average distributions received during the three preceding taxable years (or during a U.S. Holder's holding period for the Common Shares, if shorter).

Under Section 1291 of the Code, any gain recognized on the sale or other taxable disposition of Common Shares, and any excess distribution received on the Common Shares, must be ratably allocated to each day in a Non-Electing U.S. Holder's holding period for the Common Shares. The amount of any such gain or excess distribution allocated to prior years of such Non-Electing U.S. Holder's holding period for the Common Shares (other than years prior to the first taxable year of the Company beginning after December 31, 1986, for which the Company was not a PFIC) will be subject to U.S. federal income tax at the highest tax rate applicable to ordinary income in each such prior year. A Non-Electing U.S. Holder will be required to pay interest on the resulting tax liability for each such prior year, calculated as if such tax liability had been due in each such prior year. Such a Non-Electing U.S. Holder that is not a corporation must treat any such interest paid as "personal interest," which is not deductible. The amount of any such gain or excess distribution allocated to the current year of such Non-Electing U.S. Holder's holding period for the Common Shares will be treated as ordinary income in the current year, and no interest charge will be incurred with respect to the resulting tax liability for the current year.

If the Company is a PFIC for any taxable year during which a Non-Electing U.S. Holder holds Common Shares, the Company will continue to be treated as a PFIC with respect to such Non-Electing U.S. Holder, regardless of whether the Company ceases to be a PFIC in one or more subsequent taxable years. A Non-Electing U.S. Holder may terminate this deemed PFIC status by electing to recognize gain (which will be taxed under the rules of Section 1291 of the Code discussed above) as if such Common Shares were sold on the last day of the last taxable year for which the Company was a PFIC.

QEF Election

The procedure for making a QEF Election, and the U.S. federal income tax consequences of making a QEF Election, will depend on whether such QEF Election is timely. A QEF Election generally will be "timely" if it is made for the first year in a U.S. Holder's holding period for the Common Shares in which the Company is a PFIC. In this case, a U.S. Holder may make a timely QEF Election by filing the appropriate QEF Election documents with such U.S. Holder's U.S. federal income tax return for such first year. However, if the Company was a PFIC in a prior year in a U.S. Holder's holding period for the Common Shares, then in order to be treated as making a "timely" QEF Election, such U.S. Holder must elect to recognize gain (which will be taxed under the rules of Section 1291 of the Code discussed above) as if the Common Shares were sold on the qualification date for an amount equal to the fair market value of the Common Shares on the qualification date. The "qualification date" is the first day of the first taxable year in which the Company was a QEF with respect to such U.S. Holder. In addition, under very limited circumstances, a U.S. Holder may make a retroactive QEF Election if such U.S. Holder failed to file the QEF Election documents in a timely manner.

A QEF Election will apply to the taxable year for which such QEF Election is made and to all subsequent taxable years, unless such QEF Election is invalidated or terminated or the IRS consents to revocation of such QEF Election. If a U.S. Holder makes a QEF Election and, in a subsequent taxable year, the Company ceases to be a PFIC, the QEF Election will remain in effect (although it will not be applicable) during those taxable years in which the Company is not a PFIC. Accordingly, if the Company becomes a PFIC in another subsequent taxable year, the QEF Election will be effective and the U.S. Holder will be subject to the QEF rules described above during any such subsequent taxable year in which the Company qualifies as a PFIC. In addition, the QEF Election will remain in effect (although it will not be applicable) with respect to a U.S. Holder even after such U.S. Holder disposes of all of such U.S. Holder's direct and indirect interest in the Common Shares. Accordingly, if such U.S. Holder reacquires an interest in the Company, such U.S. Holder will be subject to the QEF rules described above for each taxable year in which the Company is a PFIC.

A U.S. Holder that makes a timely QEF Election generally will not be subject to the rules of Section 1291 of the Code discussed above. For example, a U.S. Holder that makes a timely QEF Election generally will recognize capital gain or loss on the sale or other taxable disposition of Common Shares.

However, for each taxable year in which the Company is a PFIC, a U.S. Holder that makes a QEF Election will be subject to U.S. federal income tax on such U.S. Holder's pro rata share of (a) the net capital gain of the Company, which will be taxed as long-term capital gain to such U.S. Holder, and (b) and the ordinary earnings of the Company, which will be taxed as ordinary income to such U.S. Holder. Generally, "net capital gain" is the excess of (a) net long-term capital gain over (b) net short-term capital loss, and "ordinary earnings" are the excess of (a)"earnings and profits" over (b) net capital gain. A U.S. Holder that makes a QEF Election will be subject to U.S. federal income tax on such amounts for each taxable year in which the Company is a PFIC, regardless of whether such amounts are actually distributed to such U.S. Holder by the Company. However, a U.S. Holder that makes a QEF Election may, subject to certain limitations, elect to defer payment of current U.S. federal income tax on such amounts, subject to an interest charge. If such U.S. Holder is not a corporation, any such interest paid will be treated as "personal interest," which is not deductible.

A U.S. Holder that makes a QEF Election generally (a) may receive a tax-free distribution from the Company to the extent that such distribution represents "earnings and profits" of the Company that were previously included in income by the U.S. Holder because of such QEF Election and (b) will adjust such U.S. Holder's tax basis in the Common Shares to reflect the amount included in income or allowed as a tax-free distribution because of such QEF Election.

Each U.S. Holder should consult its own tax advisor regarding the availability of, and procedure for making, a QEF Election. U.S. Holders should be aware that there can be no assurance that the Company will satisfy record keeping requirements that apply to a QEF, or that the Company will supply U.S. Holders with information that such U.S. Holders require to report under the QEF rules, in the event that the Company is a PFIC and a U.S. Holder wishes to make a QEF Election.

Mark-to-Market Election

A U.S. Holder may make a Mark-to-Market Election only if the Common Shares are marketable stock. The Common Shares generally will be "marketable stock" if the Common Shares are regularly traded on a qualified exchange or other market. For this purpose, a "qualified exchange or other market" includes (a) a national securities exchange that is registered with the Securities and Exchange Commission, (b) the national market system established pursuant to section 11A of the Securities and Exchange Act of 1934, or (c) a foreign securities exchange that is regulated or supervised by a governmental authority of the country in which the market is located, provided that (i) such foreign exchange has trading volume, listing, financial disclosure, surveillance, and other requirements designed to prevent fraudulent and manipulative acts and practices, remove impediments to and perfect the mechanism of a free, open, fair, and orderly market, and protect investors (and the laws of the country in which the foreign exchange is located and the rules of the foreign exchange ensure that such requirements are actually enforced) and (ii) the rules of such foreign exchange effectively promote active trading of listed stocks. If the Common Shares are traded on such a qualified exchange or other market, the Common Shares generally will be "regularly traded" for any calendar year during which the Common Shares are traded, other than in de minimis quantities, on at least 15 days during each calendar quarter.

A Mark-to-Market Election applies to the taxable year in which such Mark-to-Market Election is made and to each subsequent taxable year, unless the Common Shares cease to be "marketable stock" or the IRS consents to revocation of such election. Each U.S. Holder should consult its own tax advisor regarding the availability of, and procedure for making, a Mark-to-Market Election.

A U.S. Holder that makes a Mark-to-Market Election generally will not be subject to the rules of Section 1291 of the Code discussed above. However, if a U.S. Holder makes a Mark-to-Market Election after the beginning of such U.S. Holder's holding period for the Common Shares and such U.S. Holder has not made a timely QEF Election, the rules of Section 1291 of the Code discussed above will apply to certain dispositions of, and distributions on, the Common Shares.

A U.S. Holder that makes a Mark-to-Market Election will include in ordinary income, for each taxable year in which the Company is a PFIC, an amount equal to the excess, if any, of (a) the fair market value of the Common Shares as of the close of such taxable year over (b) such U.S. Holder's adjusted tax basis in such Common Shares. A U.S. Holder that makes a Mark-to-Market Election will be allowed a deduction in an amount equal to the lesser of (a) the excess, if any, of (i) such U.S. Holder's adjusted tax basis in the Common Shares over (ii) the fair market value of such Common Shares as of the close of such taxable year or (b) the excess, if any, of (i) the amount included in ordinary income because of such Mark-to-Market Election for prior taxable years over (ii) the amount allowed as a deduction because of such Mark-to-Market Election for prior taxable years.

A U.S. Holder that makes a Mark-to-Market Election generally will adjust such U.S. Holder's tax basis in the Common Shares to reflect the amount included in gross income or allowed as a deduction because of such Mark-to-Market Election. In addition, upon a sale or other taxable disposition of Common Shares, a U.S. Holder that makes a Mark-to-Market Election will recognize ordinary income or loss (not to exceed the excess, if any, of (a) the amount included in ordinary income because of such Mark-to-Market Election for prior taxable years over (b) the amount allowed as a deduction because of such Mark-to-Market Election for prior taxable years).

Other PFIC Rules

Under Section 1291(f) of the Code, the IRS has issued proposed Treasury Regulations that, subject to certain exceptions, would cause a U.S. Holder that had not made a timely QEF Election to recognize gain (but not loss) upon certain transfers of Common Shares that would otherwise be tax-deferred (such as gifts and exchanges pursuant to tax-deferred reorganizations under Section 368 of the Code). However, the specific U.S. federal income tax consequences to a U.S. Holder may vary based on the manner in which Common Shares are transferred.

Certain additional adverse rules will apply with respect to a U.S. Holder if the Company is a PFIC, regardless of whether such U.S. Holder makes a QEF Election. For example under Section 1298(b)(6) of the Code, a U.S. Holder that uses Common Shares as security for a loan will, except as may be provided in Treasury Regulations, be treated as having made a taxable disposition of such Common Shares.

The PFIC rules are complex, and each U.S. Holder should consult its own tax advisor regarding the PFIC rules and how the PFIC rules may affect the U.S. federal income tax consequences of the acquisition, ownership, and disposition of Common Shares.

Canadian Federal Income Tax Considerations

The summary below is restricted to the case of a holder (a "Holder") of one or more Common shares who for the purposes of the Income Tax Act (Canada) (the "Act") is a non-resident of Canada, holds his Common shares as capital property and deals at arm's length with the Company.

Dividends

A Holder will be subject to Canadian withholding tax ("Part XIII Tax") equal to 25%, or such lower rate as may be available under an applicable tax treaty, of the gross amount of any dividend paid or deemed to be paid on these Common shares. Under the 1995 Protocol amending the Canada-U.S. Income Tax Convention (1980) (the "Treaty") the rate of Part XIII Tax is applicable to a dividend on Common shares paid to a Holder who is a resident of the United States. The Company will be required to withhold the applicable amount of Part XIII Tax from each dividend so paid and remit the withheld amount directly to the Receiver General for Canada for the account of the Holder, which is 15% reduced to 5% if the shareholder owns at least 10% of the outstanding Common shares of the Company.

Disposition of Common Shares

A Holder who disposes of a Common share, including by deemed disposition on death, will not be subject to Canadian tax on any capital gain (or capital loss) thereby realized unless the Common share constituted "taxable Canadian property" as defined by the Act. A capital gain occurs when proceeds from the disposition of a share of other capital property exceeds the original cost. A capital loss occurs when the proceeds from the disposition of a share are less than the original cost. Under the Act, capital gain is effectively taxed at a lower rate as only 50% of the gain is effectively included in the Holder's taxable income.

Generally, a Common share will not constitute taxable Canadian property of a Holder unless he held the Common shares as capital property used by him carrying on a business (other than an insurance business) in Canada, or he or persons with whom he did not deal at arm's length alone or together held or held options to acquire, at any time within the five years preceding the disposition, 25% or more of the shares of any class of the capital stock of the Company. The disposition of a Common share that constitutes "taxable Canadian property" of a Holder could also result in a capital loss which can be used to reduce taxable income to the extent that such Holder can offset it against a capital gain. A capital loss cannot be used to reduce all taxable income (only that portion of taxable income derived from a capital gain).

A Holder who is a resident of the United States and realizes a capital gain on disposition of a Common share that was taxable Canadian property will nevertheless, by virtue of the Treaty, generally be exempt from Canadian tax thereon unless (a) more than 50% of the value of the Common share is derived from, or forms an interest in, Canadian real estate, including Canadian mineral resource properties, (b) the Common share formed part of the business property of a permanent establishment that the Holder has or had in Canada within the 12 months preceding disposition, or (c) the Holder (i) was a resident of Canada at any time within the ten years immediately, and for a total of 120 months during the 20 years, preceding the disposition, and (ii) owned the Common share when he ceased to be resident in Canada.

A Holder who is subject to Canadian tax in respect of a capital gain realized on disposition of a Common share must include one-half of the capital gain (taxable capital gain) in computing his taxable income earned in Canada. This Holder may, subject to certain limitations, deduct one-half of any capital loss (allowable capital loss) arising on disposition of taxable Canadian property from taxable capital gains realized in the year of disposition in respect to taxable Canadian property and, to the extent not so deductible, from such taxable capital gains of any of the three preceding years or any subsequent year.

Sales of Unregistered Securities

During the year ended December 31, 2007, we did not have any sale of securities in transactions that were not registered under the Securities Act of 1933, as amended.

Use of Proceeds

In December 2006, we raised net proceeds of $46,672,213 in a public offering of 12,075,000 shares of common stock, all of which shares were sold. The registration statements to register the shares became effective on December 15, 2006 (commission file number 333-138932) and December 18, 2006 (commission file number 333-139441). We have used all of the net proceeds from the offering for exploration and drilling activities.

Issuer Purchases of Equity Securities

During the fourth quarter of the fiscal year ended December 31, 2007, the Company did not purchase any of its equity securities.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following tables set forth selected consolidated financial data as of and for the years ended December 31, 2007, 2006, and 2005. The data as of and for the fiscal years ended December 31, 2007, 2006, and 2005 was derived from our audited annual consolidated financial statements included elsewhere in this Form 10-K.

You should read the following selected consolidated financial data together with our historical consolidated financial statements, including the related notes, and "Management's Discussion and Analysis of Financial Conditions and Results of Operations" included elsewhere in this Form 10-K.

	Year Ended December 31,		
	2007	2006	2005
Income Statement Data:			
Revenues	$ 9,320,377	$ 4,965,169	$ 453,135
Costs and Expenses Excluding Impairment	13,506,267	7,751,209	2,458,226
Asset Impairment	34,000,000	—	—
Net Income (Loss)	(38,185,890)	(2,786,040)	(2,005,091)
Net Income (Loss) per Share	$ (0.44)	$ (0.04)	$ (0.05)
Other Financial Data:			
Adjusted EBITDA(1)	$ 2,680,565	$ 947,247	$(1,210,248)

(1) We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization, (iv) impairment expense, (v) non-cash expenses relating to share based payments recognized under FAS 123R, (vi) pre-tax unrealized gains and losses on foreign currency and (vii) accretion of abandonment liability. See "Non GAAP Financial Measure" below for further discussion of this measure.

	As at December 31,		
	2007	2006	2005
Balance Sheet Data:			
Current Assets	$15,377,809	$ 61,117,145	$ 7,990,566
Property and Equipment, net	58,386,427	52,250,265	17,463,269
Total Assets	74,331,321	113,773,614	25,790,316
Current Liabilities	5,163,457	9,879,104	4,411,572
Long-term Debt	0	0	0
Stockholder's Equity	$68,293,366	$103,644,815	$21,309,671
Weighted Average Number of Shares Outstanding	87,727,621	71,425,243	44,447,269

No dividends have been declared in any of the periods presented above.

Non-GAAP Financial Measure

We use EBITDA, adjusted as described below and referred to in this Form 10-K as Adjusted EBITDA, as a supplemental measure of our performance and liquidity that is not required by, or presented in accordance with, GAAP. We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion and amortization, (iv) impairment (v) non-cash expenses relating to share based payments recognized under FAS 123R, (vi) pre-tax unrealized gains and losses on foreign currency and (vii) accretion of abandonment liability. In evaluating our business, we consider Adjusted EBITDA as a key indicator of financial operating performance and as a measure of the ability to generate cash for operational activities and future capital expenditures.

Adjusted EBITDA is not a Generally Accepted Accounting Principle ("GAAP") measure of performance. The Company uses this non-GAAP measure primarily to compare its performance with other companies in the industry that make a similar disclosure and as a measure of its current liquidity. The Company believes that this measure may also be useful to investors for the same purpose and for an indication of the Company's ability to generate cash flow at a level that can sustain or support our operations and capital investment program. Investors should not consider this measure in isolation or as a substitute for operating income or loss, cash flow from operations determined under GAAP, or any other measure for determining the Company's operating performance that is calculated in accordance with GAAP. In addition, because EBITDA is not a GAAP measure, it may not necessarily be comparable to similarly titled measures employed by other companies.

In evaluating Adjusted EBITDA, you should be aware that it excludes expenses that we will incur in the future on a recurring basis. Adjusted EBITDA has limitations as an analytical tool, and you should not consider it in isolation. Some of its limitations are:

- it does not reflect non-cash costs of our stock incentive plans, which are an ongoing component of our employee compensation program; and
- although depletion, depreciation and amortization are non-cash charges, the assets being depleted, depreciated and amortized will often have to be replaced in the future, and Adjusted EBITDA does not reflect the cost or cash requirements for such replacements.

We compensate for these limitations by relying primarily on our GAAP results and using Adjusted EBITDA only supplementally. The following table presents a reconciliation of our net income to our Adjusted EBITDA on a historical basis for each of the periods indicated:

	Year Ended December 31,		
	2007	2006	2005
Net income/(Loss)	$(38,185,890)	$(2,786,040)	$(2,005,091)
Add back:			
Depreciation, depletion & amortization & abandonment liability accretion expense	5,206,631	2,173,918	157,868
Asset impairment	34,000,000	—	—
(Gain) Loss on foreign currency exchange	(792,467)	32,008	95,864
Stock-based compensation expense	2,452,291	1,527,361	541,111
Adjusted EBITDA	$ 2,680,565	$ 947,247	$(1,210,248)

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

The following discussion and analysis should be read in conjunction with the "Selected Historical Financial Data" and our historical consolidated financial statements and the accompanying notes.

Overview and 2007 Developments

We are an independent energy company focused on the exploration, exploitation, acquisition and production of natural gas and crude oil in the United States. Our oil and natural gas reserves and operations are concentrated in two Rocky Mountain basins. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as conventional and unconventional prospects, that we have the opportunity to explore, drill and develop.

Our results of operations and financial condition are significantly affected by the success of our exploration and land leasing activity, the resulting production and reserves, oil and natural gas commodity prices, and the costs related to operating our properties.

In 2007, we made significant progress in our exploration activities related to our prospective land positions with exploratory drilling and by obtaining additional geological and geophysical data. Overall, we invested capital of $45.1 million in our oil and gas operations including $39.2 spent on drilling, completion and related infrastructure and $5.9 million spent on land leasing and geological and geophysical data. Although we have not obtained significant production with these expenditures, this investment has provided us with a platform to build on as we further develop our exploration plays.

Our understanding of the natural gas in place in the Baxter Formation of the Vermillion Basin and the completion requirements to get that gas has improved with each well we have drilled. We drilled and completed four deep gas wells. This includes the Horseshoe Basin #5-3 well where we expanded the over-pressured, gas-bearing area by drilling six miles from the nearest existing production. We expect that we will connect this well to gathering facilities in the summer of 2008, which we believe will add significant cash inflows. We completed the acquisition and are currently analyzing the 3-D seismic study of a 43-square mile area on our land holdings in the northern portion of our acreage in the Vermillion Basin. Early in 2008, we announced the signing of an exploration agreement with Devon Energy Production Company, L.P., which, among other things, allows Devon to earn ownership in our Vermillion properties through drilling three exploratory wells at their sole cost. With this agreement, development will continue to move ahead in this play and our capital requirements will be limited. We expect that the completed 3-D seismic studies acquired in 2007 will prove useful well into the future as we seek to expand our production base through additional drilling.

Our acreage position acquired in 2007 and early 2008 in the Bakken play of Dunn County, North Dakota will, we believe, prove to be one of the most exciting developments onshore North America. We continued to expand our acreage position in Dunn County, North Dakota, where we will target the Bakken shale. Pending regulatory approvals, we expect to have leased over 30,000 net acres in this play bordered by producing wells. In the third quarter of 2007, we entered into an agreement with another independent exploration and production company to jointly lease and develop a block of acreage in this play. This agreement provides for shared participation in future drilling and leasing activities in the play. Subject to permitting by the Bureau of Land Management and the Bureau of Indian Affairs, we expect to begin drilling operations early in 2008. In the Williston Basin of North Dakota and Montana, we completed two oil wells in 2007 and have recently completed an 18-square mile 3-D seismic program. We expect the results of this 3-D seismic will lead to additional drilling opportunities in 2008.

With contractual agreements in place with industry leaders to partner in the development of the Vermillion Basin and certain acreage in the Dunn County Bakken play, we believe we have excellent exposure to the potential of these developments without a large capital requirement.

As of December 31, 2007, we had estimated proved reserves of 2.7 billion cubic feet ("BCF") of natural gas and 932 thousand barrels ("MBbls") of oil with a present value discounted at 10% of $36.2 million. Our reserves are 75% proved developed and are comprised of 33% natural gas and 67% crude oil on an energy equivalent basis. Our December 31, 2007, natural gas reserves reflect a downward revision of the December 31, 2006, reserves of 1.1 BCF, primarily from the revision of reserves associated with the underperformance of our Vermillion Basin exploratory wells. In December 2006, we had recently completed the North Trail #4-36 and based on early results and geological studies, the well was estimated to have 1.6 BCF of reserves. Subsequently, in 2007, due to various mechanical problems, this well's production did not meet anticipated flow rates. As a result, in the 2007 reserve study, this well does not contribute significantly. Offsetting this downward revision, we had discoveries and extensions during 2007 of 1.6 BCF of natural gas and 496 MBbls of oil primarily related to the Horseshoe Basin #5-3 well.

We had gas sales in 2007 of 548 Mcf per day and crude oil sales of 282 barrels per day. This was an increase of 71% and 66% over the volumes sold in 2006. Revenues from oil and gas sales increased 88% to $7.8 million in 2007 with 14% of the change due to the increase in commodity prices and 86% of the change due to increased sales volumes. Lease operating expenses increased 52% to $936,000. Overall, total production expenses increased 82% to $1.8 million, primarily due to increased production taxes related to the increased revenues.

Our revenues are directly affected by oil and natural gas commodity prices, which can fluctuate dramatically. The commodity prices are beyond our control and are difficult to predict. During recent years, including 2007 and into 2008, we have seen significant volatility in oil and natural gas prices. We believe that spot market prices reflect worldwide concerns about producers' ability to ensure sufficient supply to meet increasing demand amid a host of uncertainties caused by political instability, a weak U.S. dollar, and crude oil refining and natural gas infrastructure constraint. Prices we have received have varied widely depending on commodity and location of salespoints. In 2007, we experienced record crude oil prices while in Wyoming we elected to shut in gas production because of extremely low natural gas prices. Overall, the average crude oil price we received for the year was $65.73 per barrel versus $55.52 per barrel in 2006, while our average gas price received was $5.25 per Mcf compared to $6.13 per Mcf in 2006.

In 2007, our financial position and results of operations were affected significantly by an asset impairment related to the carrying value of our developed properties. During 2007, we incurred capital expenditures of approximately $40 million related to our oil and gas drilling operations and related infrastructure. Except for wells currently in progress, these expenditures increased the Company's full cost pool, but did not add proportionately to our proved reserves' present value calculated under the current SEC guidelines. The value of Kodiak's proved reserves as calculated periodically throughout the year did not exceed the costs included in the full cost pool. Consequently the Company recorded a cumulative asset impairment of $34 million during 2007.

Outlook

In 2008, we expect to continue to focus on the leasing and permitting related to the Dunn County, North Dakota Bakken prospect. We expect that this will culminate in a multiple well drilling program beginning in the summer of 2008. With the acreage position gained in 2007 and early 2008, we expect that most of our capital budget will be focused on the drilling of this project. In the Vermillion Basin, with the gains in knowledge as a result of our exploratory efforts in 2006 and 2007, and a partner with excellent unconventional gas development expertise, we expect to see significant progress in the development of this play.

We believe that oil and gas prices will remain volatile during 2008. As a result of increases in the prices of domestic oil and natural gas over the past several years, and the corresponding increased demand for oil field services, shortages have developed, and we have seen an escalation in rig rates, field service costs, material prices and all costs associated with drilling, completing and operating wells. If oil and natural gas prices remain high relative to historical levels, we anticipate that the recent trends toward increasing costs and equipment and personnel shortages will continue. While we have identified prospects to drill, our ability to grow could be adversely affected by these shortages and price increases.

We plan to make capital expenditures of approximately $12.6 million for 2008. We will continuously evaluate our capital expenditures budget and make adjustments from time to time as our results of operations and other factors dictate. Of the $12.6 million, we have allocated $2.1 million to our operations in the Vermillion Basin primarily related to geophysical studies and land leasing. This assumes no contribution to the costs of drilling up to three gross wells which will be paid for by Devon as part of the Devon Agreement. We have estimated that we will incur an additional $10.4 million of capital expenditures in the exploration of the Bakken play in North Dakota and for workovers of existing Bakken wells to the west of our Dunn County acreage position. Depending on the timing of the receipt of permits from regulatory agencies, rig availability and the success of each well, we expect to drill three to four gross wells in this area in 2008. In addition to this $12.6 million budget, we have other prospects that are in the early stages of exploration. Further spending on these prospects is contingent on the success of the core projects described above.

To execute the 2008 plan, we have many challenges. Our working capital of $10.2 million as of December 31, 2007, will not be sufficient to completely support all of our potential exploration opportunities in 2008. Although we expect that cash flow from operations will increase with the success of the core projects, currently these funds provide only a limited amount of additional working capital. To further develop these projects and fund the contingent prospects, we will need to obtain alternative sources of capital. We anticipate that we will seek to obtain additional funding, either by means of debt or equity financings or by entering into additional joint venture agreements with other companies, the availability of which there can be no assurance.

Liquidity and Capital Resources

Our primary cash requirements are for exploration, development and acquisition of oil and gas properties. We have historically financed our operations, property acquisitions and capital investments from the proceeds of private offerings of our equity securities and, more recently to a limited extent, from cash generated from operations. We do not currently generate sustaining cash flow from our oil and gas operations, although our future depends on our ability to generate oil and natural gas operating cash flow. As of December 31, 2007, we had working capital of $10.2 million as compared to $51.2 million at December 31, 2006, and no long-term debt. During the fiscal year ended December 31, 2007, our additions to oil and natural gas properties totaled $45.1 million including accrued expenditures.

Due to our active oil and natural gas activities, we have experienced, and expect to continue to experience, substantial working capital requirements. As a result of our agreement with Devon, we expect to maintain a high level of activity in the Vermillion Basin, while not being responsible for significant capital expenditures. If we continue to build on our most recent success in this play, we would anticipate additional capital requirements by late 2008 and into 2009. By reducing the capital requirements of the continuing Vermillion Basin exploration, we are able to allocate our existing capital to the North Dakota Bakken play. Through an exploration agreement with a joint venture partner in this play, we have limited our initial capital exposure to an approximate 50% working interest in each of the early wells. As a result, we adopted a preliminary budget for capital expenditures in 2008 of $12.6 million. Additional anticipated expenditures will be predicated upon the results of our drilling in these core areas. We intend to fund these capital expenditures, other commitments and working capital requirements with existing capital, expected cash flow from operations, anticipated joint venture arrangements, and finally the potential funds raised from the sale of our equity. We do not expect to significantly fund our oil and gas operations with debt unless and until we generate sufficient cash flow from oil and natural gas operations to service the debt.

Our ability to fund our operations in future periods will depend upon our future operating performance, and more broadly, on the availability of equity and debt financing, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. We cannot be certain that additional funding will be available on acceptable terms, or at all. If we are unable to raise additional capital when required or on acceptable terms, we may have to significantly delay, scale back or discontinue our drilling or exploration program, seek to enter into additional joint venture arrangements with third parties, or seek to sell one or more of our properties.

Operating Results

Fiscal Year Ended December 31, 2007 Compared to Fiscal Year Ended December 31, 2006

Natural Gas sales revenues. Natural gas sales revenues increased by $334,407 to $1,053,332 for the year ended December 31, 2007, from $718,925 for the same period of 2006. Increased natural gas sales volumes more than offset price declines between the periods. Natural gas sales volumes were 200,191 Mcf for the year ended December 31, 2007, compared to 117,326 Mcf for the same period in 2006, whereas the average price we realized on the sale of our natural gas declined by 14% to $5.25 per Mcf. The increase in gas production volumes is due to an increase in the number of operating gas wells, from six wells in 2006 to fourteen in 2007. The increased sales were partially offset by reduced volumes due to shutting in wells during the third and fourth quarters of 2007 as a result of low natural gas prices received for our Vermillion Basin production.

Oil sales revenues. Oil sales revenues increased by $3,323,836 to $6,764,017 for the year ended December 31, 2007, from $3,440,181 for 2006. In 2007, we benefitted from both increased oil sales volumes and higher realized oil prices. Oil sales volumes were 102,913 barrels for 2007 compared to 61,966 barrels for the same period in 2006, whereas the average price we realized on the sale of our oil increased by 18% to $65.73 per barrel for the year ended December 31, 2007, from $55.52 for the same period in 2006. The increase in oil sales volumes are a result of having a full year's production for wells drilled during 2006 as well as two additional wells drilled and completed in 2007.

Interest Income. Interest income increased by $696,967 to $1,503,029 in 2007 from $806,062 for the same period in 2006. The increase was due to the investment of funds received from our December 2006 sale of shares of our common stock.

Oil and gas production expense. Our oil and gas production expense increased by $793,033 to $1,757,718 for the fiscal year ended December 31, 2007, from $964,685 for the same period in 2006. The increase is partially due to an 52% increase in lease operating expense reflecting our growing production base and number of producing wells. Also, severance taxes increased 125% due to increased revenues from growing sales volumes and higher prices and the expiration of incentive production taxes.

Depletion, depreciation, amortization and abandonment liability accretion ("DDA") expense. Our depletion, depreciation, amortization and abandonment liability accretion expense increased by $3,032,713 to $5,206,631 for the fiscal year ended December 31, 2007, from $2,173,918 for the same period in 2006. The increase reflects our growing depletable and depreciable asset base and our production base. Overall the rate of DDA expense has increased from $26.70 per barrel of oil equivalent to $38.19 per BOE. This increase was impacted by the addition of expenditures related to our exploration and development activities to our depletable basis, or full cost pool, without a proportionate increase in proved reserves. Additionally, because of changes in development plans and the drilling of unproductive wells, certain leasehold costs were impaired which increased the full cost pool.

Asset impairment. As of March 31, 2007, based on current oil and gas prices of $55.12 per barrel and $4.16 per Mcf, the Company's full cost pool exceeded the present value of the Company's estimated future net revenue discounted at 10%. Therefore, impairment expense of $14,000,000 was recorded during the quarter ended March 31, 2007. Based on the Company's evaluation of oil and gas reserves at September 30, 2007, using weighted average realized oil and gas prices of $71.59 per barrel of crude oil and $3.96 per Mcf of natural gas, the Company's full cost pool again exceeded the ceiling limitation by approximately $20.0 million and an impairment expense was recorded for this amount during the quarter ended September 30, 2007.

The year-to-date impairment of $34,000,000 is primarily the result of the Company's inability to establish production and qualified reserves in its deep Vermillion Basin project, uneconomic natural gas prices in Wyoming, and the impairment of certain undeveloped properties in Wyoming and North Dakota.

As with many resource plays in the early stages of development, significant expenditures have been and will continue to be required to understand the parameters of the deep Vermillion Basin play. As of December 31, 2007, we have drilled four exploratory wells in the Baxter, Frontier, and Dakota Formations to better understand the resource potential. In the second half of 2007, we focused on acquiring additional geologic and geophysical data from these wells and the acquisition and interpretation of an extensive seismic study over the northern portion of our acreage. While we are optimistic about the long-term potential of this prospect we have not established significant proved reserves for the deep Vermillion Basin. As a result, the value of the development to date calculated under SEC guidelines does not offset the cost of the wells and related acreage in the full cost pool.

General and administrative expense. General and administrative expense increased by $2,753,788 to $7,334,386 for the fiscal year ended December 31, 2007, from $4,580,598 for the same period in 2006. Included in the general and administrative expense for the fiscal year ended December 31, 2007 is a stock-based compensation charge of $2,452,291 for options issued to officers, directors and employees compared to $1,527,361 for the year ended December 31, 2006. The increase in general and administrative expenses for the fiscal year ended December 31, 2007, also reflects an increase in our level of activity and an increase in the number of employees and related salary and payroll expense. As of December 31, 2007, we had fifteen full-time employees and three contract consultants, as compared to 12 full-time employees at December 31, 2006. Salary and related expenses increased by $1,068,361 to $2,915,173 for the year ended December 31, 2007, from $1,846,812 in 2006. In 2007, we also incurred additional costs of $142,000 related to outside consulting services and additional audit requirements as a result of the adoption of Section 404 of Sarbanes-Oxley.

Gain on currency exchange. In 2007, we benefited from an increase in the value of our Canadian dollars with a $792,467 gain on currency exchange as compared to a loss in 2006 of $32,008. Our Canadian dollar balance has largely been converted to U.S. dollars as of year-end 2007 so we do not expect similar gains in the future.

Net loss. Our net loss increased by $35,399,849 to a net loss of $38,185,890 for the year ended December 31, 2007, from a net loss of $2,786,041 for 2006. As more fully described above, the asset impairment of $34,000,000 was the primary cause of the increase. In addition, the increases in our oil and natural gas production revenues, interest income and gain on currency exchange were more than offset by increases in oil and natural gas production expense, depletion, depreciation, amortization and abandonment liability expenses and general and administrative expenses.

Adjusted EBITDA. Our Adjusted EBITDA increased by $1,733,319 to $2,680,565 for the year ended December 31, 2007, from $947,246 for the same period of 2006. As shown in the following table, this increase is the primarily the result of increased oil and gas revenues only partially offset by increased production expenses and general and administrative expenses. For further discussion of this non-GAAP measure and a reconciliation of this measure to net income, see Non-GAAP Financial Measure in Item 4 of this 10-K.

	For the Year Ended December 31,		
	2007	2006	Change
Oil and gas production revenues	$7,817,349	$4,159,106	$3,658,246
Interest revenue	1,503,029	806,062	696,967
Total revenue	9,320,378	4,965,168	4,355,210
Oil and gas production expense	1,757,718	964,685	793,033
General and administrative expense excluding stock compensation	4,882,095	3,053,237	1,828,858
Adjusted EBITDA	$2,680,565	$ 947,246	$1,733,319

Fiscal Year Ended December 31, 2006, Compared to Fiscal Year Ended December 31, 2005

Natural Gas sales revenues. Natural gas and natural gas liquid sales revenues increased by $493,402 to $718,926 for the fiscal year ended December 31, 2006, from $225,524 for the same period of 2005. Increased natural gas sales volumes more than offset price declines between the periods. Natural gas and natural gas liquid production volumes were 116,316 Mcf and 1,008 Mcf, respectively, for the fiscal year ended December 31, 2006, compared to 31,751 Mcf for the same period in 2005, whereas the average price we realized on the sale of our natural gas declined by 22% to $5.56 per Mcf for the fiscal year ended December 31, 2006, from $7.11 per Mcf for the same period of 2005. The increase in gas production volumes is due to an increase in the number of producing gas wells, from one well at December 31, 2005, to six at December 31, 2006.

Oil sales revenues. Oil sales revenues increased by $3,300,126 to $3,440,182 for the fiscal year ended December 31, 2006, from $140,056 for the same period of 2005. Oil sales volumes and realized oil prices increased during the period. Oil sales volumes were 61,966 barrels for the fiscal year ended December 31, 2006, compared to 2,699 barrels for the same period in 2005, whereas the average price we realized on the sale of our oil increased by 7% to $55.52 per barrel for the fiscal year ended December 31, 2006, from $51.89 for the same period in 2005. The increase in oil sales volumes is due to an increase in the number of operating wells, from one well at December 31, 2005, to seven at December 31, 2006.

Interest Income. Interest income increased by $718,506 to $806,061 in 2006 for the fiscal year ended December 31, 2006, from $87,555 for the same period in 2005. The increase was due to the investment of funds received from our March and December 2006 sale of shares of our common stock.

Oil and gas production expense. Our oil and gas production expense increased by $762,800 to $964,685 for the fiscal year ended December 31, 2006, from $201,885 for the same period in 2005. The increase is partially due to paying severance taxes on production from exploratory wells in Montana during the last part of 2006, whereas these same wells were exempt from state severance taxes in 2005. The increase also reflects our growing production base and number of producing wells.

Depletion, depreciation, amortization and abandonment liability accretion expense. Our depletion, depreciation, amortization and abandonment liability accretion expense increased by $2,016,050 to $2,173,918 for the fiscal year ended December 31, 2006, from $157,868 for the same period in 2005. The increase reflects our growing depletable and depreciable asset base and our production base.

General and administrative expense. General and administrative expense increased by $2,577,989 to $4,580,598 for the fiscal year ended December 31, 2006, from $2,002,609 for the same period in 2005. Included in the general and administrative expense for the fiscal year ended December 31, 2006 in accordance with SFAS No. 123R is a stock-based compensation charge of $1,527,361 for options issued to officers, directors and employees compared to $541,111 for the year ended December 31, 2005. The increase in general and administrative expenses for the fiscal year ended December 31, 2006, also reflects an increase in our level of activity and an increase in the number of employees and related salary and payroll expense. During the fiscal year ended December 31, 2006, we had twelve full-time employees and two part-time contract consultants, an increase of six from the same period in 2005. Salary and payroll expense increased by $728,912 to $1,677,220 for the fiscal year ended December 31, 2006, from $948,308 for the same period in 2005. During the fiscal year ended December 31, 2006 we paid bonuses totaling $707,000 to employees and management, compared to $111,500 during the same period in 2005. In 2006, we also incurred additional legal expenses and costs related to outside accounting services, as a result of our filings with the Securities and Exchange Commission, costs associated with our application for trading on the AMEX, and costs incurred in connection with our reporting to shareholders. We commenced trading on the AMEX on June 21, 2006.

Loss on currency exchange. Loss on currency exchange decreased by $63,856 to $32,008 for the fiscal year ended December 31, 2006 from $95,864 for the same period in 2005. We received a portion of the proceeds from our March 2006 private placement of common shares in Canadian dollars.

Net loss. Our net loss increased by $780,949 to a net loss of $2,786,040 for the fiscal year ended December 31, 2006 from a net loss of $2,005,091 for the same period of 2005. As more fully described above, the increases in our oil and natural gas production revenues, interest income and gain on currency exchange were more than offset by increases in oil and natural gas production expense, depletion, depreciation, amortization and abandonment liability expenses and general and administrative expenses.

Adjusted EBITDA. Our Adjusted EBITDA increased by $2,157,495 to $947,247 for the year ended December 31, 2006, from $(1,210,248) for the same period of 2005. As shown in the following table, this increase is the primarily the result of increased oil and gas revenues only partially offset by increased production expenses and general and administrative expenses. For further discussion of this non-GAAP measure and a reconciliation of this measure to net income, see Non-GAAP Financial Measure in Item 4 of this 10-K.

	For the Year Ended December 31,		
	2006	2005	Change
Oil and gas production revenues	$4,159,106	$ 365,580	$3,793,526
Interest revenue	806,062	87,555	718,507
Total revenue	4,965,168	453,135	4,512,033
Oil and gas production expense	964,685	201,885	762,800
General and administrative expense excluding stock compensation	3,053,237	1,461,498	1,591,739
Adjusted EBITDA	$ 947,246	$(1,210,248)	$2,157,495

Financial Instruments and Other Instruments

As at December 31, 2007, we had cash, accounts payable and accrued liabilities which are carried at approximate fair value because of the short maturity date of those instruments. Our management believes that we are not exposed to significant interest, currency or credit risks arising from these financial instruments.

Research and Development

As an exploration stage natural resource company, we do not normally engage in research and there were no development activities, or research and development expenditures made in the last three fiscal years.

Trend Information

Our industry has experienced a significant increase in the cost of drilling rigs and related oil field services. Drilling rigs have been difficult to contract and we cannot be assured that we can secure third party contracts. Commodity prices are at or near all time levels and we cannot be assured that they will continue at these levels. It is difficult to assure that we can retain qualified employees during a competitive period in the industry. Some or all of these situations are likely to have a material effect upon our net sales or revenues, income from continuing operations, profitability, liquidity or capital resources, or cause reported financial information not necessarily to be indicative of future operating results or financial condition.

Off-balance sheet arrangements

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Contractual obligations

The following table lists as of December 31, 2007, information with respect to our known contractual obligations:

	Payments due by Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Obligations—Office Facilities	$1,235,182	$257,569	$541,276	436,337	—

We have not included asset retirement obligations as discussed in note 2 of the accompanying audited financial statements, as we cannot determine with accuracy the timing of such payments.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with generally accepted accounting principals in the United States, or GAAP, requires our management to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements and the reported amounts of revenues and expenses during the reporting period. The following is a summary of the significant accounting policies and related estimates that affect our financial disclosures.

Oil and Natural Gas Reserves

We believe estimated reserve quantities and the related estimates of future net cash flows are the most important estimates made by an exploration and production company such as ours because they affect the perceived value of our company, are used in comparative financial analysis ratios, and are used as the basis for the most significant accounting estimates in our financial statements, including the periodic calculation of depletion, depreciation and impairment of our proved oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. We determine anticipated future cash inflows and future production and development costs by applying benchmark prices and costs, including transportation, quality and basis differentials, in effect at the end of each period to the estimated quantities of oil and natural gas remaining to be produced as of the end of that period. We reduce expected cash flows to present value using a discount rate that depends upon the purpose for which the reserve estimates will be used. For example, the standardized measure calculation required by Statement of Financial Accounting Standards ("SFAS") No. 69, Disclosures about Oil and Gas Producing Activities, requires us to apply a 10% discount rate. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established proved producing oil and natural gas properties, we make considerable effort to estimate our reserves, including through the use of independent reserves engineering consultants. We expect that periodic reserve estimates will change in the future as additional information becomes available or as oil and natural gas prices and operating and capital costs change. We evaluate and estimate our oil and natural gas reserves as of December 31 of each year and at other such times throughout the year that we deem appropriate. For purposes of depletion, depreciation, and impairment, we adjust reserve quantities at all interim periods for the estimated impact of acquisitions and dispositions. Changes in depletion, depreciation or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period in which the reserves or net cash flow estimate changes.

Impairment of Long-lived Assets

We record our property and equipment at cost. The cost of our unproved properties is withheld from the depletion base as described above, until such a time as the properties are either developed or abandoned. We review these properties periodically for possible impairment. We provide an impairment allowance on unproved property when we determine that the property will not be developed or the carrying value will not be realized. We evaluate the reliability of our proved properties and other long-lived assets whenever events or changes in circumstances indicate that the recording of impairment may be appropriate. Our impairment test compares the expected undiscounted future net revenue from a property, using escalated pricing, with the related net capitalized costs of the property at the end of the applicable period. When the net capitalized costs exceed the undiscounted future net revenue of a property, the cost of the property is added to the full cost pool.

Revenue Recognition

Our revenue recognition policy is significant because revenue is a key component of our results of operations and of the forward-looking statements contained in our analysis of liquidity and capital resources. We derive our revenue primarily from the sale of produced natural gas and crude oil. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs, which are reported as separate expenses. We record revenue in the month our production is delivered to the purchaser, but payment is generally received 30 to 90 days after the date of production. At the end of each month, we make estimates of the amount of production that we delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices and other factors as the basis for these estimates. We record the variances between our estimates and the actual amounts we receive in the month payment is received.

Asset Retirement Obligations

We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties including without limitation the costs of reclamation of our drilling sites, storage and transmission facilities and access roads. We base our estimate of the liability on the industry experience of our management and on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates and determine the credit-adjusted risk-free rate to use. Our estimated asset retirement obligations are reflected in our depreciation, depletion and amortization calculations over the remaining life of our oil and gas properties.

Stock-Based Compensation

We account for stock-based compensation under the provisions of SFAS No. 123R, Accounting for Stock-Based Compensation. This statement requires us to record expense associated with the fair value of stock-based compensation. We currently use the Black-Scholes option valuation model to calculate stock based compensation.

Oil and Natural Gas Properties—Full Cost Method of Accounting

We use the full cost method of accounting whereby all costs related to the acquisition and development of oil and natural gas properties are capitalized into a single cost center referred to as a full cost pool. These costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities.

Capitalized costs, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by independent petroleum engineers. For this purpose, we convert our petroleum products and reserves to a common unit of measure.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the full cost pool and becomes subject to depletion calculations.

Proceeds from the sale of oil and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless the sale would alter the rate of depletion by more than 25%. Royalties paid, net of any tax credits, received are netted against oil and natural gas sales.

In applying the full cost method, we perform a ceiling test on properties that restricts the capitalized costs less accumulated depletion from exceeding an amount equal to the estimated undiscounted value of future net revenues from proved oil and natural gas reserves, as determined by independent petroleum engineers. The estimated future revenues are based on sales prices achievable under existing contracts and posted average reference prices in effect at the end of the applicable period, and current costs, and after deducting estimated future general and administrative expenses, production related expenses, financing costs, future site restoration costs and income taxes. Under the full cost method of accounting, capitalized oil and natural gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and natural gas reserves, plus the cost, or estimated fair value if lower, of unproved properties. Should capitalized costs exceed this ceiling, we would recognize an impairment.

Foreign Currency Fluctuations

Monetary items denominated in a foreign currency, other than U.S. dollars, are converted into U.S. dollars at exchange rates prevailing at the balance sheet date. Foreign currency denomination revenue and expense items are translated at exchange rates prevailing at the transaction date. Gains or losses arising from the translations are included in operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our primary market risk consists of market changes in oil and natural gas prices. Prospective revenues from the sale of products or properties will be impacted by oil and natural gas prices. A $1.00 per Mcf change in the market price of natural gas would result in a change of approximately $200,000 in our gross gas production revenue for the fiscal year ended December 31, 2007. A $1.00 per barrel change in the market price of oil would result in a change of approximately $102,000 in our gross oil production revenue for the fiscal year ended December 31, 2007. The impact on any potential sale of property cannot be readily determined.

Interest Rate Risk

We currently maintain some of our available cash in redeemable short-term investments, classified as cash equivalents, and our reported interest income from these short-term investments could be adversely affected by any material changes in U.S. dollar interest rates. A 1% change in the interest rate would result in a change of approximately $263,000 in our interest income for the fiscal year ended December 31, 2007 if all of our cash were invested in interest-bearing notes.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Kodiak Oil & Gas Corp.

We have audited the consolidated balance sheets of Kodiak Oil & Gas Corp. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall 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 financial position of Kodiak Oil & Gas Corp. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Kodiak Oil & Gas Corp.'s and subsidiaries' internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 14, 2008 expressed an unqualified opinion on the effectiveness of Kodiak Oil & Gas Corp.'s internal control over financial reporting.

HEIN & ASSOCIATES LLP

Denver, Colorado
March 13, 2008

KODIAK OIL & GAS CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 13,015,318	$ 58,469,263
Accounts receivable		
Trade	1,373,843	1,877,185
Accrued sales revenues	789,652	666,990
Prepaid expenses and other	198,996	103,707
Total Current Assets	15,377,809	61,117,145
Property and equipment (full cost method), at cost:		
Proved oil and gas properties	77,272,437	27,167,338
Unproved oil and gas properties	21,904,737	19,607,474
Wells in progress	414,074	7,700,415
Less-accumulated depletion, depreciation, amortization, accretion and asset impairment	(41,204,821)	(2,224,962)
Net oil and gas properties	58,386,427	52,250,265
Other property and equipment, net of accumulated depreciation of $176,458 in 2007 of $102,231 in 2006	312,017	181,752
Restricted investments	255,068	224,452
Total Assets	$ 74,331,321	$113,773,614
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 5,163,457	$ 9,879,104
Noncurrent Liabilities:		
Asset retirement obligation	874,498	249,695
Total Liabilities	6,037,955	10,128,799
Commitments and Contingencies—Note 7		
Stockholders' Equity:		
Common stock, no par value; unlimited authorized		
Issued: 87,992,926 shares in 2007 and 87,548,426 shares in 2006		
Paid-in capital	115,094,923	112,260,482
Accumulated deficit	(46,801,557)	(8,615,667)
Total Stockholders' Equity	68,293,366	103,644,815
Total Liabilities and Stockholders' Equity	$ 74,331,321	$113,773,614

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2007	2006	2005
Revenues:			
Gas production	$ 1,053,331	$ 718,926	$ 225,524
Oil production	6,764,017	3,440,182	140,056
Interest	1,503,029	806,061	87,555
Total revenue	9,320,377	4,965,169	453,135
Cost and expenses:			
Oil and gas production	1,757,717	964,685	201,885
Depletion, depreciation, amortization and accretion	5,206,631	2,173,918	157,868
Asset impairment	34,000,000	—	—
General and administrative	7,334,386	4,580,598	2,002,609
(Gain)/loss on currency exchange	(792,467)	32,008	95,864
Total costs and expenses	47,506,267	7,751,209	2,458,226
Net loss	$(38,185,890)	$(2,786,040)	$(2,005,091)
Basic & diluted weighted-average common shares outstanding	87,742,996	71,425,243	44,447,269
Basic & diluted net loss per common share	$ (0.44)	$ (0.04)	$ (0.05)

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.

STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Contributed Surplus	Accumulated Deficit	Total Equity
Balance December 31, 2004:	33,875,283	$ 8,663,014	$ (3,824,536)	$ 4,838,478
Issuance of stocks for cash:				
—pursuant to private placement	17,000,000	15,644,243		15,644,243
—pursuant to exercise of warrants	3,496,875	2,515,678		2,515,678
—pursuant to exercise of options	100,000	12,122		12,122
Stock issuance costs		(292,370)		(292,370)
Employee stock grants	75,000	55,500		55,500
Stock-based compensation		541,111		541,111
Net loss			(2,005,091)	(2,005,091)
Balance December 31, 2005:	54,547,158	$ 27,139,298	$ (5,829,627)	$ 21,309,671
Issuance of stocks for cash:				
—pursuant to public offering	31,589,268	89,555,687		89,555,687
—pursuant to exercise of options	1,412,000	384,372		384,372
Stock issuance costs		(6,346,236)		(6,346,236)
Stock-based compensation		1,527,361		1,527,361
Net loss			(2,786,040)	(2,786,040)
Balance December 31, 2006:	87,548,426	112,260,482	(8,615,667)	103,644,815
Issuance of stocks for cash:				
—pursuant to exercise of options	363,500	382,150		382,150
Employee stock grants	81,000	125,200		125,200
Stock-based compensation		2,327,091		2,327,091
Net loss			(38,185,890)	(38,185,890)
Balance December 31, 2007:	87,992,926	$115,094,923	$(46,801,557)	$ 68,293,366

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.

CONSOLIDATED STATEMENTS OF CASHFLOWS

	For the Years Ended December 31,		
	2007	2006	2005
Cash flows from operating activities:			
Net loss	$(38,185,890)	$ (2,786,040)	$ (2,005,091)
Reconciliation of net loss to net cash provided by (used in) operating activities:			
Depletion, depreciation, amortization and accretion	5,206,631	2,173,918	157,868
Asset impairment	34,000,000	—	—
Asset retirement	(29,893)	—	—
Stock-based compensation	2,452,291	1,527,361	541,111
Changes in current assets and liabilities:			
Accounts receivable-trade	503,342	(1,429,204)	(424,322)
Accounts receivable-accrued sales revenues	(122,661)	(440,585)	(227,500)
Prepaid expenses and other	(95,289)	(73,076)	785
Accounts payable and accrued liabilities	(1,655,119)	4,168,775	735,928
Net cash provided by (used in) operating activities	2,073,412	3,141,149	(1,221,221)
Cash flows from investing activities:			
Oil and gas properties	(47,649,681)	(35,426,830)	(11,853,969)
Equipment	(229,210)	(52,976)	(124,196)
Restricted investment: designated as restricted	(30,616)	(82,052)	(153,000)
Restricted investment: undesignated as restricted	—	10,600	—
Net cash (used in) investing activities	(47,909,507)	(35,551,258)	(12,131,165)
Cash flows from financing activity:			
Proceeds from the issuance of shares	382,150	89,940,060	18,227,543
Stock issuance costs	—	(6,346,236)	(292,370)
Net cash provided by financing activities	382,150	83,593,824	17,935,173
Net change in cash and cash equivalents	(45,453,945)	51,183,715	4,582,787
Cash and cash equivalents at beginning of the period	58,469,263	7,285,548	2,702,761
Cash and cash equivalents at end of the period	$ 13,015,318	$ 58,469,263	$ 7,285,548
Supplemental cash flow information			
Oil & gas property accrual included in Accounts payable and accrued liabilities	$ 1,544,868	$ 4,605,396	$ 3,306,641
Asset retirement obligation	$ 526,868	$ 164,503	$ 67,000

SEE ACCOMPANYING NOTES

Note 1—Organization

Description of Operations

Kodiak Oil & Gas Corp. and its subsidiary ("Kodiak" or the "Company") is a public company listed for trading on the American Stock Exchange (AMEX) and whose corporate headquarters are located in Denver, Colorado, USA. The Company is an independent energy company engaged in the exploration, exploitation, development, acquisition and production of natural gas and crude oil entirely in the western United States.

The Company was incorporated (continued) in the Yukon Territory on September 28, 2001.

Note 2—Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc. All significant inter-company balances and transactions have been eliminated. The majority of the Corporation's business is transacted in US dollars and, accordingly, the financial statements are expressed in US dollars. The accompanying consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles.

Certain amounts in the 2006 and 2005 audited consolidated financial statements have been reclassified to conform to the 2007 audited consolidated financial statement presentation; such reclassifications had no effect on the 2006 or 2005 net loss.

Use of Estimates in the Preparation of Financial Statements

The preparation of the financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates on historical experience and on various other assumptions it believes to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, the Company believes that its estimates are reasonable.

Cash and Cash Equivalents

Cash and cash equivalents consist of all highly liquid investments that are readily convertible to cash and have maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Restricted Investment

The restricted investment balance as of December 31, 2007, is comprised of: (a) $185,271 certificate of deposit to collateralize a surety bond to provide for state bonding requirements for plugging and abandonment liabilities; and (b) $69,797 certificate of deposit to collateralize the costs of office improvements that will be released over the four year remaining term of the lease at $17,450 per year. At December 31, 2006 the balance was comprised of: (a) $182,052 certificate of deposit to collateralize a surety bond to provide for state bonding requirements for plugging and abandonment liabilities; and (b) $42,400 certificate of deposit to collateralize the costs of office improvements that will be released over the four year remaining term of the lease at $10,600 per year.

Note 2—Basis of Presentation and Significant Accounting Policies (Continued)

Concentration of Credit Risk

The Company's cash equivalents and short-term investments are exposed to concentrations of credit risk. The Company manages and controls this risk by investing these funds with major financial institutions. The Company may at times have balances in excess of the federally insured limits.

The Company's receivables are comprised of oil and gas revenue receivables and joint interest billings receivable. The amounts are due from a limited number of entities. Therefore, the collectability is dependent upon the general economic conditions of the few purchasers and joint interest owners. The receivables are not collateralized. However, to date the Company has had minimal bad debts.

Significant Customers

During the year ended December 31, 2007, over 80% of the Company's production was sold to one customer, Eighty Eight Oil LLC. However, the Company does not believe that the loss of a single purchaser, including Eighty Eight Oil, would materially affect the Company's business because there are numerous other purchasers in the area in which the Company sells its production. For the years ended December 31, 2007, 2006 and 2005 purchases by the following companies exceeded 10% of the total oil and gas revenues of the company.

	For the Year Ended December 31,		
	2007	2006	2005
Eighty Eight Oil LLC	80%	76%	0%
ABQ Gas Marketing	12%	0%	25%
Duke Energy Field Services	3%	11%	37%
Nexen Marketing	0%	0%	38%

Oil and Gas Producing Activities

The Company follows the full cost method of accounting for oil and gas operations whereby all costs related to the exploration and development of oil and gas properties are initially capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition and exploration activities. Proceeds from property sales are generally credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to theses costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full costs pool.

Costs capitalized, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by the Company's engineers and audited by independent petroleum engineers. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

For depletion and depreciation purposes, relative volumes of oil and gas production and reserves are converted at the energy equivalent rate of six thousand cubic feet of natural gas to one barrel of crude oil. Under the full costs method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost, or estimated fair value, if lower of unproved properties. Should capitalized costs exceed

Note 2—Basis of Presentation and Significant Accounting Policies (Continued)

this ceiling, an impairment is recognized. The present value of estimated future net revenues is computed by applying current prices of oil and gas to estimated future production of proved oil and gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves assuming the continuation of existing economic conditions.

Estimated reserve quantities and future net cash flows have the most significant impact on the Company because these reserve estimates are used in providing a measure of the Company's overall value. These estimates are also used in the quarterly calculations of depletion, depreciation and impairment of the Company's proved properties.

Estimating accumulations of gas and oil is complex and is not exact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the Securities and Exchange Commission (the "SEC"), such as gas and oil 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 optimal method of determining proved reserve estimates is based upon a decline analysis method, which consists of extrapolating future reservoir pressure and production from historical pressure decline and production data. The accuracy of the decline analysis method generally increases with the length of the production history. Most of the Company's wells have been producing less than six years and for some, less than a year. Because of this short production history, other generally less accurate methods such as volumetric analysis and analogy to the production history of wells of ours and other operators in the same reservoir were used in conjunction with the decline analysis method to determine the Company's estimates of proved reserves including developed producing, developed non-producing and undeveloped. As the Company's wells are produced over time and more data is available, the estimated proved reserves will be re-determined at least on an annual basis and may be adjusted based on that data.

Because of significant exploration activity during late 2006 and 2007 and the short production history on many existing wells at the time of the preparation of the December 31, 2006, reserve report, the Company updated its reserves as of September 30, 2007. Commodity prices used in this analysis include the Plains Marketing West Texas Intermediate crude oil posted price of $78.25 per barrel, the Platts Gas Daily Northern, Ventura midpoint price of $5.63 per MMBtu, and the Platts Gas Daily Questar Rocky Mountain midpoint price of $0.98 per MMBtu. All prices are as of September 30, 2007, and are further adjusted for transportation and quality differentials. The resulting weighted average realized oil and gas prices for the production of proved reserves at September 30, 2007, was $71.59 per barrel of crude oil and $3.96 per Mcf of natural gas. Wells with gas sold based on the Questar Rocky Mountain price were largely uneconomic and therefore have little effect on the weighted average sales price. Based on this analysis, the Company's full cost pool exceeded the ceiling limitation by approximately $20.0 million and an impairment expense was recorded for this amount during the quarter ended September 30, 2007. At March 31, 2007, the Company's full cost pool also exceeded the ceiling limitation based on oil and gas prices at March 31, 2007 of $55.12 per barrel and $4.16 per Mcf and an impairment expense of $14.0 million was recorded during the quarter ended March 31, 2007.

The total 2007 impairment of $34,000,000 is primarily the result of the Company's inability to establish production and qualified reserves in its deep Vermillion Basin project, low natural gas prices in Wyoming, and the impairment of certain undeveloped properties in Wyoming and North Dakota.

Wells in Progress

Wells in progress at December 31, 2007 and 2006 represent the costs associated with the drilling of wells in Montana, North Dakota and Wyoming. Since the wells have not reached total depth or been completed as of December 31 they were classified as wells in progress and were withheld from the depletion calculation and the ceiling test. The costs for these wells will be transferred to proved property when the wells reach total depth and are cased and will become subject to depletion and the ceiling test calculation in future periods.

Impairment of Long-lived Assets

The Company's unproved properties are evaluated quarterly for the possibility of potential impairment. Kodiak has drilled three non-commercial wells on its Great Bear prospect in northern North Dakota since late 2005. As a result and because of Management's reduced drilling plans in the southern portion of this acreage, the Company impaired approximately half of this acreage in the third quarter of 2007. The Company also impaired certain acreage in Wyoming unrelated to its Vermillion play due to reduced expectations. In the year ended December 31, 2006, the Company did not recognize any impairment losses.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, vehicles, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is recorded using the straight-line method over the estimated useful lives of three years for computer equipment, and five years for office equipment and vehicles. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, accounts receivable and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments.

Revenue Recognition

The Company records revenues from the sales of natural gas and crude oil when they are produced and sold. The Company may have an interest with other producers in certain properties, in which case the Company uses the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by the Company. In addition, the Company records revenue for its share of gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company also reduces revenue for other owners' gas sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company's over and under produced gas balancing positions are considered in the Company's proved oil and gas revenues. Gas imbalances at December 31, 2007 and 2006 were not significant.

Note 2—Basis of Presentation and Significant Accounting Policies (Continued)

Stock-Based Compensation

Prior to January 1, 2006, the Company accounted for stock-based compensation under the provisions of Statement of Financial Accounting Standards ("SFAS") No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123 required us to record an expense associated with the fair value of stock-based compensation.

On January 1, 2006, we adopted SFAS No. 123(R), "Accounting for Stock-Based Compensation," using the modified prospective method. Under the modified prospective method, the adoption of SFAS No. 123(R) applies to new awards and to awards modified, repurchased, or cancelled after December 31, 2005, as well as to the unvested portion of awards outstanding as of January 1, 2006. In accordance with the modified prospective method, Kodiak has not adjusted the financial statements for periods ended prior to January 1, 2006. The Company did not recognize any one-time effects of the adoption and continued to use similar option valuation models and assumptions as were used prior to January 1, 2006. There is no fair-value-based compensation expense associated with prior awards that were not vested on the date of the adoption of SFAS No. 123(R).

Kodiak currently use the Black-Scholes option valuation model to calculate stock-based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. Changes in these assumptions can materially affect the fair value estimate.

Asset Retirement Obligation

The Company follows SFAS No. 143, "Accounting for Asset Retirement Obligations," which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The increase in carrying value of a property associated with the capitalization of an asset retirement cost is included in proved oil and gas properties in the consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs. The future cash outflows associated with settling the asset retirement obligations that have been accrued in the accompanying balance sheets are excluded from the ceiling test calculations. The Company also depletes the estimated dismantlement and abandonment costs, net of salvage values, associated with future development activities that have not yet been capitalized as asset retirement obligations. These costs are also included in the ceiling test calculation. The asset retirement liability will be allocated to operating expense by using a systematic and rational method. As of December 31, 2007 and 2006 the Company has recorded a net asset of $660,986 and $218,165 and a related liability of $874,498 and $249,695, respectively. In 2007, the Company revised its estimated dismantlement and abandonment costs based upon the actual costs of recently plugged and

Note 2—Basis of Presentation and Significant Accounting Policies (Continued)

abandoned wells. The information below reconciles the value of the asset retirement obligation for the periods presented.

	For the Years Ended December 31, 2007	2006
Balance beginning of period	$249,695	$ 69,073
Liabilities incurred	60,289	164,503
Liabilities settled	(3,021)	0
Revisions in estimated cash flows	482,544	—
Accretion expense	84,991	16,119
Balance end of period	$874,498	$249,695

Recently Issued Accounting Pronouncements:

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes ("FIN 48"). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. The interpretation was effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 did not have a material impact on the Company's consolidated financial position, results of operations or cash flows.

In September 2006, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements" ("FAS 157"). This Statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements but does not change the requirements to apply fair value in existing accounting standards. Under FAS 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 principal or most advantageous market. The standard clarifies that fair value should be based on the assumptions market participants would use when pricing the asset or liability. The provisions of FAS 157 are to be applied prospectively, except for the initial impact on the following three items, which are required to be recorded as an adjustment to the opening balance of retained earnings in the year of adoption: (1) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities", (2) existing hybrid financial instruments measured initially at fair value using the transaction price, and (3) a position in a financial instrument that was measured at fair value using a blockage factor prior to initial application of FAS 157. FAS 157 was effective and adopted by the Company as of January 1, 2008. The adoption of FAS 157 did not have a material impact on the Company's January 1, 2008 balances of retained earnings.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities-Including an Amendment of FASB Statement No. 115" ("FAS 159"). This Statement allows an entity the option to elect fair value for the initial and subsequent measurement for

Note 2—Basis of Presentation and Significant Accounting Policies (Continued)

certain financial instruments and other items that are not currently required to be measured at fair value. If a company chooses to record eligible items at fair value, the company must report unrealized gains and losses on those items in earnings at each subsequent reporting date. FAS 159 also prescribes presentation and disclosure requirements for assets and liabilities that are measured at fair value pursuant to this standard. FAS 159 was effective for the Company as of January 1, 2008. The Company does not expect that the adoption of FAS 159 will have a material effect on its financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141-R, "Business Combinations" ("FAS 141R") which revised SFAS No. 141, "Business Combinations" ("FAS 141"). This pronouncement is effective for the Company's financial statements issued after January 1, 2009. Under FAS 141, organizations utilized the announcement date as the measurement date for the purchase price of the acquired entity. FAS 141R requires measurement at the date the acquirer obtains control of the acquiree, generally referred to as the acquisition date. FAS 141R will have a significant impact on the accounting for transaction costs, restructuring costs as well as the initial recognition of contingent assets and liabilities assumed during a business combination. Under FAS 141R, adjustments to the acquired entity's deferred tax assets and uncertain tax position balances occurring outside the measurement period are recorded as a component of the income tax expense, rather than goodwill. As the provisions of FAS 141R are applied prospectively, the impact to the Company cannot be determined until the transactions occur.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" ("FAS 160"). This Statement establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. FAS 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited. The Company does not expect that the adoption of FAS 160 will have a material effect on its financial position or results of operations.

In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 108 ("SAB 108"). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 was effective for fiscal years ending after November 15, 2006. The Company adopted SAB 108 and it did not have a material impact on its financial position or results from operations.

Note 3—Oil and Gas Property

The following table presents information regarding the Company's net costs incurred in the purchase of proved and unproved properties, and in the exploration and development activities:

	For the Years Ended December 31,		
	2007	2006	2005
Property Acquisition costs:			
Proved	$ —	$ —	$ 909,637
Unproved	4,285,277	7,225,875	5,476,788
Exploration costs	28,960,843	12,534,859	1,027,153
Development costs	11,869,900	17,129,283	7,814,031
Total	$45,116,021	$36,890,017	$15,227,609
Total excluding asset retirement obligation	$44,576,209	$36,725,586	$15,160,609

Note 3—Oil and Gas Property (Continued)

Depletion expense related to the proved properties per equivalent BOE of production for the years ended December 31, 2007, 2006, and 2005 were $39.30, $25.63, and $14.45, respectively.

At December 31, 2007 and 2006, the Company's unproved properties consisted of leasehold acquisition costs in the following areas:

	2007	2006
Colorado	$ 2,166,250	$ 962,990
Montana	2,151,632	2,233,629
North Dakota	4,723,540	3,089,757
Wyoming	12,863,315	13,321,098
	$21,904,737	$19,607,474

The following table sets forth a summary of oil and gas property costs not being amortized as of December 31, 2007 by the year in which such costs were incurred:

	Unproved Additions by Year
Prior	$ 706,748
2005	3,864,832
2006	10,249,063
2007	7,084,095
Total	$21,904,737

Note 4—Wells in Progress

The following table reflects the net changes in capitalized additions to wells in progress during 2007 and 2006, and does not include amounts that were capitalized and reclassified to producing wells in the same period.

	For the Years Ended December 31	
	2007	2006
Beginning balance at January 1,	$ 7,700,415	$ 2,461,087
Additions to capital wells in progress costs pending the determination of proved reserves	414,074	7,700,415
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves to full cost pool	(7,700,415)	(2,461,087)
Ending balance December 31,	$ 414,074	$ 7,700,415

Note 4—Wells in Progress (Continued)

The following table provides an aging of capitalized wells in progress costs based on the date the drilling was completed and the number of projects for which wells in progress have been capitalized since the completion of drilling.

	For the Years Ended December 31	
	2007	2006
Wells in progress capitalized for one year or less	$414,074	$7,700,415
Wells in progress capitalized for one year or more	—	—
Ending balance at December 31	$414,074	$7,700,415
Number of projects with wells in progress that have been capitalized less than one year	2	3

Note 5—Common Stock

In March 2006, the Company issued 19,514,268 common shares in a private placement to a group of accredited investors for gross proceeds of $39,444,438. The Company paid commissions and expenses of $2,907,199. In December 2006, the Company issued 12,075,000 common shares in a public placement for gross proceeds of $50,111,250. The Company paid commission and expenses of $3,439,037.

In December 2005, the Company issued 17,000,000 common shares in a private placement to a group of accredited investors for gross proceeds of $15,644,243. The Company paid $292,370 in commissions and expenses. In 2005, the Company issued 3,496,875 common shares through the exercise of warrants for gross proceeds of $2,515,678.

In March 2004, the Company issued 11,428,572 common shares in a private placement to a group of accredited investors for gross proceeds of $2,972,061. The Company paid $263,801 in commissions and expenses. During 2004, the Company issued 7,948,036 common shares through the exercise of warrants for gross proceeds of $2,408,058.

During 2007, the Company issued 363,500 common shares through the exercise of employee options for gross proceeds of $382,150. During 2006, the Company issued 1,412,000 common shares through the exercise of options for gross proceeds of $384,372. During 2005, the Company issued 100,000 common shares through the exercise of employee options for gross proceeds of $12,122.

Note 6—Compensation Plan

Stock-based Compensation Plan

In 2007 the Company adopted the 2007 Stock Incentive Plan (the "2007 Plan"), which replaced the Incentive Share Option Plan (the "Pre-existing Plan"). The 2007 Plan authorizes it to issue stock options, stock appreciation rights (SARs), restricted stock and restricted stock units, performance awards, stock or property, stock awards and other stock-based awards may be granted to any employee, consultant, independent contractor, director or officer of the Company. A total of 8,000,000 shares of common stock may be issued under the 2007 Plan, which includes shares issuable under the Pre-existing Plan pursuant to options outstanding as of the effective date of the 2007 Plan. No more than 8,000,000 shares may be used for stock issued pursuant to incentive stock options and the number of shares available for granting restricted stock and restricted stock units shall not exceed 1,000,000, subject to adjustment as defined in the 2007 Plan. The Company granted 2,044,000 stock options and 81,000 shares of restricted stock in 2007. As of February 28, 2008, the Company has outstanding options to purchase 6,112,000 common shares at prices from $0.45 to $6.26.

Note 6—Compensation Plan (Continued)

For the years ended December 31, 2007, 2006 and 2005, the Company recorded stock-based compensation of $2,452,291, $1,527,361, and $541,111 respectively.

The following assumptions were used for the Black-Scholes model to calculate the stock-based compensation expense for the years presented:

	For the Periods Ended		
	December 31, 2007	December 31, 2006	December 31, 2005
Risk free rates	4.46 - 5.89%	4.56 - 5.25%	4.3%
Dividend yield	0%	0%	0%
Expected volatility	53.46 - 56.26%	62.79 - 64.92%	81.34%
Weighted average expected stock option life	5.86 yrs	3.36 yrs	2.5 yrs
The weighted average fair value at the date of grant for stock options granted is as follows:			
Weighted average fair value per share	$ 3.33	$ 1.58	$ 0.60
Total options granted	2,044,000	2,110,000	900,000
Total weighted average fair value of options granted	$ 6,800,579	$ 3,339,312	$541,111

A summary of the stock options outstanding is as follows:

	Number of Options	Weighted Average Exercise Price
Balance outstanding at December 31, 2005	3,938,500	$0.58
Granted	2,110,000	$3.41
Exercised	(1,412,000)	$0.27
Balance outstanding at December 31, 2006	4,636,500	$1.96
Granted	2,044,000	$5.83
Exercised	(363,500)	$1.05
Forfeited	(205,000)	$3.81
Balance outstanding at December 31, 2007	6,112,000	$3.25
Options exercisable at December 31, 2007	3,943,831	$2.16

Note 6—Compensation Plan (Continued)

At December 31, 2007, stock options outstanding are as follows:

Exercise Price	Number of Shares	Expiry Date
$0.45	925,000	March 1, 2009
$0.45	75,000	March 1, 2014
$0.90	338,000	August 23, 2009
$1.08	800,000	October 16, 2010
$1.08	75,000	October 17, 2015
$2.11	50,000	March 12, 2011
$3.17	1,200,000	April 14, 2011
$3.17	100,000	April 14, 2016
$4.03	285,000	June 28, 2011
$3.81	220,000	October 31, 2011
$6.26	1,720,000	May 24, 2017
$3.81	210,000	August 15, 2017
$3.04	114,000	October 15, 2017
	6,112,000	

The aggregate intrinsic value of both outstanding and vested options as of December 31, 2007, was $3,167,195.70, based on the Company's December 31, 2007 closing common stock price of $2.20. This amount would have been received by the option holders had all option holders exercised their options as of that date. The total grant date fair value of the shares vested during 2007 was $2,223,496. As of December 31, 2007, there was $5,234,112 of total unrecognized compensation cost related to unamortized options. That cost is expected to be recognized over a period of three years.

The Company granted 81,000 restricted stock awards in 2007. Of these awards, 60,000 vest on a graded-vesting basis of one-third immediately and one-third at each anniversary date over a two year service period and 21,000 vest on a graded-vesting basis of one-third at each anniversary date over a three year service period. The Company recognizes compensation cost over the requisite service period for the entire award with the expense recognized upon vesting. The fair value of restricted stock grants is based on the stock price on the grant date and the Company assumes no annual forfeiture rate. As of December 31, 2007, there were 61,000 unvested shares with a weighted-average grant date fair value of $4.91 per share and $299,680 of total unrecognized compensation cost related to non-vested restricted stock which is expected to be recognized over a three-year period.

Note 7—Commitments and Contingencies

The Company leases office facilities under an operating lease agreement that expires on June 30, 2012. Rent expense was $144,298 in 2007, $62,738 in 2006, and $48,164 in 2005. The Company has no other material capital leases and no other operating lease commitments.

Note 7—Commitments and Contingencies (Continued)

The following table shows the annual rentals per year for the life of the lease:

Years ending December 31,	
2008	$ 257,569
2009	264,929
2010	276,347
2011	289,257
2012	147,080
Total	$1,235,182

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not pay such commitments, the acreage positions or wells may be lost.

Note 8—Income Taxes

The Company has available a cumulative net operating loss of approximately $39.3 million that may be carried forward to reduce taxable income in future years. They will begin to expire in 2009.

Significant components of the Company's future tax assets and liabilities, after applying enacted corporate income tax rates, are as follows:

	2007	2006	2005
Future income tax assets:			
Net tax losses carried forward	$ 13,315,114	$ 3,943,586	$ 1,062,000
Stock based compensation	1,792,234	956,773	414,000
Exploration and development expenses	1,267,766	(1,789,320)	149,000
Other	(298,716)	92,262	—
	16,076,398	3,203,301	1,625,000
Valuation allowance for future income tax assets	$(16,076,398)	$(3,203,301)	$(1,625,000)
Future income tax asset, net	$ —	$ —	$ —

A reconciliation of the provision (benefit) for income taxes computed at the statutory rate:

	2007	2006	2005
Federal	35.0%	35.0%	35.0%
State	2.8%	4.5%	4.5%
Other	0.0%	(.03)%	0.0%
Valuation Allowance	(37.8)%	(39.2)%	(39.5)%
Net	0.0%	0.0%	0.0%

The components of income taxes related to Canadian operations were not significant to the net tax assets or rate reconciliation.

The Company adopted the provisions of Financial Accounting Board Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48"), an interpretation of FASB Statement No. 109, "Accounting for Income Taxes", on January 1, 2007. The interpretation clarifies the accounting for uncertainty in income taxes recognized in our financial statements and provides guidance on

Note 8—Income Taxes (Continued)

derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The adoption of FIN 48 resulted in no impact to our consolidated financial statements and we have no unrecognized tax benefits that would impact our effective rate.

Note 9—Differences Between Canadian and United States Accounting Principles

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America which differ in certain respects with those principles and practices that the Company would have followed had its financial statements been prepared in accordance with accounting principles and practices generally accepted in Canada. Management does not believe the financial statements would vary materially had they been prepared in accordance with Canadian GAAP or that any recently issued, not yet effective, Canadian accounting standards if currently adopted could have a material effect on the accompanying financial statements.

Note 10—Quarterly Financial Information (Unaudited):

The Company's quarterly financial information for fiscal 2007 and 2006 is as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2007				
Total revenue	$ 2,140,527	$ 2,324,130	$ 2,505,998	$ 2,349,722
Revenue from oil and gas operations	1,576,817	1,869,602	2,200,249	2,170,681
Gross profit(a)	146,796	536,837	(297,002)	466,369
Net loss	(14,454,833)	(449,246)	(21,984,875)	(1,296,936)
Basic and diluted net loss per share	$ (.17)	$ (.01)	$ (0.25)	$ (0.02)
Year Ended December 31, 2006				
Total revenue	$ 1,012,251	$ 1,125,266	$ 1,273,035	$ 1,554,616
Revenue from oil and gas operations	908,578	862,099	1,040,589	1,347,839
Gross profit(a)	408,148	133,679	351,739	126,939
Net loss	(5,515)	(1,008,110)	(389,288)	(1,383,128)
Basic and diluted net loss per share	$ (.00)	$ (.01)	$ (0.01)	$ (0.02)

(a) Excludes interest revenue, asset impairment expense, and general and administrative expense, and (gain) on currency exchange

Supplemental Oil and Gas Reserve Information (Unaudited)

The following reserve quantity and future net cash flow information for 2007 was prepared by the Company and audited by Netherland, Sewell & Associates, Inc. (NSA), independent petroleum engineers. The information for 2006 was prepared by NSA and for 2005 was prepared by Sproule and Associates.

The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from know reservoirs under existing economic and operating conditions. Proved developed

Supplemental Oil and Gas Reserve Information (Unaudited) (Continued)

oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company's proved reserves are located in the continental United States.

The following table sets forth information for the years ended December 31, 2007, 2006 and 2005 with respect to changes in the Company's proved (i.e. proved developed and undeveloped) reserves:

	Crude Oil (Bbls)	Natural Gas (Mcf)
December 31, 2004	—	—
Revisions of previous estimates	—	—
Extensions, discoveries, and other additions	524,408	2,866,967
Sale of reserves	—	—
Production	(2,699)	(31,751)
December 31, 2005	521,709	2,835,216
Revisions of previous estimates	(156,246)	(1,990,509)
Purchase of reserves	—	—
Extensions, discoveries, and other additions	230,422	1,674,003
Sale of reserves	—	—
Production	(62,983)	(116,277)
December 31, 2006	532,902	2,402,433
Revisions of previous estimates	7,128	(1,089,893)
Purchase of reserves	—	—
Extensions, discoveries, and other additions	495,954	1,616,247
Sale of reserves	—	—
Production	(103,953)	(232,635)
December 31, 2007	932,031	2,696,152
Proved developed reserves, included above:		
December 31, 2005	309,400	1,828,600
December 31, 2006	493,300	2,399,400
December 31, 2007	623,950	2,455,661

Standardized Measure of Discounted Future Net Cash Flows (Unaudited):

SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying benchmark prices and costs, including transportation, quality and basis differentials, in effect at year-end to the year-end estimated quantities of oil and gas to be produced in the future. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved oil and gas reserves in place at the end of the period, using

Supplemental Oil and Gas Reserve Information (Unaudited) (Continued)

year-end costs and assuming continuation of existing economic conditions, plus Company overhead incurred attributable to operating activities.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the Securities and Exchange Commission. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are basis for the valuation process. The following values for the 2007 oil and gas reserves are based on the December 31, 2007 natural gas price of $6.04 per MMBtu (Questar Rocky Mountains price) or $6.75 per MMBtu (Northern Ventura price) and crude oil price of $92.50 per barrel (West Texas Intermediate price). The values for the 2006 reserves are based on the December 31, 2006 natural gas price of $3.95 per MMBtu (Questar Rocky Mountain price) or $5.70 per MMBtu (Northern Ventura price) and crude oil price of $57.75 per barrel (West Texas Intermediate price). All prices are adjusted for transportation, quality and basis differentials.

The following summary sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in SFAS No. 69:

	Year Ended December 31,		
	2007	2006	2005
Future oil and gas sales	$ 95,071,835	$37,634,700	$ 51,182,477
Future production costs	(22,127,559)	(8,920,900)	(13,355,083)
Future development costs	(10,669,553)	(2,492,500)	(5,342,500)
Future income taxes	—	—	(10,980,498)
Future net cash flows	62,274,723	26,221,300	21,504,396
10% annual discount	(26,080,552)	(6,631,500)	(7,301,589)
Standardized measure of discounted future net cash flows	$ 36,194,171	$19,589,800	$ 14,202,807

The principle sources of change in the standardized measure of discounted future net cash flows are:

	Year ended December 31,		
	2007	2006	2005
Balance at beginning of period	$19,589,800	$14,202,806	$ —
Sales of oil and gas, net	(6,059,632)	(3,194,424)	(163,695)
Net change in prices and production costs	10,126,811	(4,965,063)	—
Net change in future development costs	(8,068,070)	630,351	—
Extensions and discoveries	15,524,174	11,720,816	18,320,720
Revisions of previous quantity estimates	(5,356,105)	(7,798,876)	—
Previously estimated development costs incurred	8,742,935	2,187,500	—
Net change in income taxes	—	3,954,218	(3,954,218)
Accretion of discount	1,537,322	2,107,952	—
Other	156,936	744,520	—
Balance at end of period	$36,194,171	$19,589,800	$14,202,807

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Management of the Company, including the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), have evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this Form 10-K. The term "disclosure controls and procedures" means controls and other procedures established by the Company that are designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Based upon their evaluation of the Company's disclosure controls and procedures, the CEO and the CFO concluded that the disclosure controls are effective to provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure and are effective to provide reasonable assurance that such information is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms.

The Company, including its CEO and CFO, does not expect that its internal controls and procedures will prevent or detect all error and all fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Management's Annual Report on Internal Control Over Financial Reporting

In accordance with Item 308 of SEC Regulation S-K, management is required to provide an annual report regarding internal controls over our financial reporting. This report, which includes management's assessment of the effectiveness of our internal controls over financial reporting, is found below.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records which in reasonable detail accurately and fairly reflect the transactions and dispositions of the company's assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made in accordance with established company policies and procedures; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

Management (with the participation of the principal executive officer and principal financial officer) conducted an evaluation of the effectiveness of the company's internal control over financial reporting as of December 31, 2007 based on the framework set forth in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the company's internal control over financial reporting was effective as of December 31, 2007. Hein & Associates LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this report, has issued an attestation report on the effectiveness of internal control over financial reporting.

Attestation Report of Registered Public Accounting Firm

The attestation report required under this Item 9A is set forth below under the caption "Report of Independent Registered Public Accounting Firm."

Changes in Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Kodiak Oil & Gas Corp.

We have audited Kodiak Oil & Gas Corp.'s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Kodiak Oil & Gas Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Kodiak Oil & Gas Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Kodiak Oil & Gas Corp. as of December 31, 2007 and 2006, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007, and our report dated March 14, 2008 expressed an unqualified opinion.

HEIN & ASSOCIATES LLP

Denver, Colorado
March 13, 2008

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information responsive to Items 401, 405, 406 and 407 of Regulation S-K to be included in our definitive Proxy Statement for our 2007 Annual Meeting of Shareholders, to be filed within 120 days of December 31, 2007, pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the "2008 Proxy Statement"), is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information responsive to Items 402 and 407 of Regulation S-K to be included in our 2008 Proxy Statement is incorporated herein by reference.

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

The information responsive to Items 201(d) and 403 of Regulation S-K to be included in our 2008 Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information responsive to Items 404 and 407 of Regulation S-K to be included in our 2008 Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information responsive to Item 9(e) of Schedule 14A to be included in our 2008 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed With This Report

1. FINANCIAL STATEMENTS

The following consolidated financial statements of the Company are filed as a part of this report:

2. FINANCIAL STATEMENT SCHEDULES
None.

3. EXECUTIVE COMPENSATION PLANS AND ARRANGEMENTS
Kodiak Oil & Gas Corp. Incentive Stock Option Plan identified in the exhibit list below.

(b) Exhibits

Exhibit Number	Description
3.1(1)	Certificate of Continuance of Kodiak Oil & Gas Corp., dated September 20, 2001
3.2(1)	Articles of Continuation of Kodiak Oil & Gas Corp.
3.3(1)	General By-Law No. 1
4.1(1)	Kodiak Oil & Gas Corp. Incentive Stock Option Plan
4.2(2)	Kodiak Oil & Gas Corp. 2007 Stock Incentive Plan
4.3(3)	Form of Incentive Stock Option Agreement for 2007 Stock Incentive Plan
4.4(3)	Form of Employee Non-incentive Stock Option Agreement for 2007 Stock Incentive Plan
4.5(3)	Form of Directors' Non-incentive Stock Option Agreement for 2007 Stock Incentive Plan
4.6(3)	Form of Restricted Stock Award Agreement for 2007 Stock Incentive Plan
4.7(3)	Non-Incentive Stock Option Agreement between Kodiak Oil & Gas Corp. and Lynn A. Peterson
4.8(3)	Non-Incentive Stock Option Agreement between Kodiak Oil & Gas Corp. and James E. Catlin
10.1(4)	Form of Stock Purchase Agreement, dated as of March 3, 2006, among Kodiak Oil & Gas Corp. and certain investors
10.2(5)	Fourth Amendment to Lease, dated February 14, 2007, between Transwestern Broadreach WTC, LLC and Kodiak Oil & Gas (USA) Inc.

Exhibit Number	Description
10.3	Fifth Amendment to Lease, dated May 31, 2007 between Transwestern Broadreach WTC, LLC and Kodiak Oil & Gas (USA) Inc.
10.4(6)	Executive Employment Agreement dated January 1, 2008 between Kodiak Oil & Gas Corp. and Lynn A. Peterson.
10.5(6)	Executive Employment Agreement dated January 1, 2008 between Kodiak Oil & Gas Corp. and James E. Catlin.
10.6(6)	Executive Employment Agreement dated January 1, 2008 between Kodiak Oil & Gas Corp. and James P. Henderson.
10.7(7)	Form of Underwriting Agreement Among Kodiak Oil & Gas Corp. and the underwriters named therein.
14.1(4)	Code of Business Conduct and Ethics
16.1(8)	Letters regarding change in certifying accountant filed on May 8, 2006
21.1(9)	Subsidiaries of the Registrant
23.1	Consent of Hein & Associates LLP
23.2	Consent of Netherland Sewell & Associates, Inc.
23.3	Consent of Sproule Associates Inc.
31.1	Certification of the Chief Executive Officer required by Rule 13a-14(a) or Rule 15d-14(a)
31.2	Certification of the Chief Accounting Officer required by Rule 13a-14(a) or Rule 15d-14(a)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350
32.2	Certification of the Chief Accounting Officer pursuant to 18 U.S.C. Section 1350

(1) Incorporated by reference to the Registrant's Registration Statement on Form 20-F (SEC File No. 000-51635), filed on November 23, 2005.

(2) Incorporated by reference to the Registrant's Schedule 14A Definitive Proxy Statement (SEC File No. 001-32920), filed on April 27, 2007.

(3) Incorporated by Reference to the Registrant's 2007 Stock Incentive Plan on Form S-8 (SEC File No. 333-144878), filed on July 26, 2007.

(4) Incorporated by reference to the Registrant's Annual Report on Form 20-F for the Fiscal Year Ended December 31, 2005 (SEC File No. 000-51635), filed on May 2, 2006.

(5) Incorporated by reference to the Registrant's Annual Report on Form 10-K (SEC File No. 001-32920), filed on March 27, 2007.

(6) Incorporated by reference to the Registrant's Current Report on Form 8-K (SEC File No. 001-32920), filed on January 9, 2008.

(7) Incorporated by reference to Registrant's Registration Statement on Form F-1/A Amendment No. 1 (SEC File No. 333-138932), filed on December 6, 2006.

(8) Incorporated by reference to the Registrant's Form 6-K (SEC File No. 000-51635), filed on May 8, 2006.

(9) Incorporated by reference to the Registrant's Registration Statement on Form F-1 (SEC File No. 333-138932), filed on November 22, 2006.

GLOSSARY OF TERMS

The following technical terms defined in this section are used throughout this Form 10-K:

(a) "2-D seismic or 2-D data" means seismic data that is acquired and processed to yield a two-dimensional cross-section of the subsurface.

(b) "3-D seismic or 3-D data" means seismic data that is acquired and processed to yield a three-dimensional picture of the subsurface.

(c) "Bbl" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

(d) "BOE" means barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

(e) "Bore hole" means the wellbore itself, including the openhole or uncased portion of the well. Bore hole may refer to the inside diameter of the wellbore wall, the rock face that bounds the drilled hole.

(f) "Coalbed methane" is methane gas produced as a result of the coalification process, whereby plant material is progressively converted to coal, generating large quantities of methane-rich gas which are stored within the coal.

(g) "Completion" means the installation of permanent equipment for the production of oil or natural gas.

(h) "Delay rental" means a payment made to the lessor under a non-producing oil and natural gas lease at the end of each year to continue the lease in force for another year during its primary term.

(i) "Developed acreage" means the number of acres that are allocated or assignable to producing wells or wells capable of production.

(j) "Development well" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

(k) "Dry hole" means a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(l) "Exploratory well" means a well drilled either (a) in search of a new and as yet undiscovered pool of oil or gas or (b) with the hope of significantly extending the limits of a pool already developed (also known as a "wildcat well").

(m) "Farmin" means an agreement which allows a party to earn a full or partial working interest (also knows as an "earned working interest") in an oil and natural gas lease in return for providing exploration funds.

(n) "Farmout" means an agreement whereby the owner of the leasehold or working interest agrees to assign a portion of his interest in certain acreage subject to the drilling of one or more specific wells or other performance by the assignee as a condition of the assignment. Under a farmout the owner of the leasehold or working interest may retain some interest such as an overriding royalty interest, an oil and natural gas payment, offset acreage or other type of interest.

(o) "Federal Unit" means acreage under federal oil and natural gas leases subject to an agreement or plan among owners of leasehold interests, which satisfies certain minimum arrangements and has been approved by an authorized representative of the U.S. Secretary of the Interior, to consolidate under a cooperative unit plan or agreement for the development of such acreage comprising a common oil and natural gas pool, field or like area, without regard to separate leasehold ownership of each participant and providing for the sharing of costs and benefits on a basis as defined in such agreement or plan under the supervision of a designated operator.

(p) "Fee land" means the most extensive interest that can be owned in land, including surface and mineral (including oil and natural gas) rights.

(q) "Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

(r) "Fracturing" means mechanically inducing a crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock in order to enhance the permeability of rocks greatly by connecting pores together.

(s) "Gas" or "Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

(t) "Gross Acres" or "Gross Wells" means the total acres or wells, as the case may be, in which we have a working interest.

(u) "Hydraulic fracturing" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases permeability and porosity.

(v) "Horizontal drilling" means a well bore that is drilled laterally.

(w) "Landowner royalty" means that interest retained by the holder of a mineral interest upon the execution of an oil and natural gas lease which usually amounts to ⅛ of all gross revenues from oil and natural gas production unencumbered with any expenses of operation, development, or maintenance.

(x) "Leases" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

(y) "Mcf" is an abbreviation for "1,000 cubic feet," which is a unit of measurement of volume for natural gas.

(z) "Methane" means a colorless, odorless, flammable gas, CH4, the first member of the methane series.

(aa) "Net Acres" or "Net Wells" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

(bb) "Net revenue interest" means all of the working interests less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

(cc) "NYMEX" means New York Mercantile Exchange.

(dd) "Overriding royalty" means an interest in the gross revenues or production over and above the landowner's royalty carved out of the working interest and also unencumbered with any expenses of operation, development or maintenance.

(ee) "Operator" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

(ff) "Paid-Up Lease" means a lease for which the aggregate lease payments are paid in full on or prior to the commencement of the lease term.

(gg) "Payout" means the point in time when the cumulative total of gross income from the production of oil and natural gas from a given well (and any proceeds from the sale of such well) equals the cumulative total cost and expenses of acquiring, drilling, completing, and operating such well, including tangible and intangible drilling and completion costs.

(hh) "Prospect" means a geological area which is believed to have the potential for oil and natural gas production.

(ii) "PV-10 value" means the present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

(jj) "Productive well" means a well that is producing oil or gas or that is capable of production.

(kk) "Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

(ll) "Proved reserves" means the estimated quantities of oil, gas and gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(mm) "Proved undeveloped reserves" means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(nn) "Recompletion" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

(oo) "Reserve life" represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

(pp) "Royalty" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

(qq) "Royalty interest" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

(rr) "Undeveloped acreage" means lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

(ss) "Undeveloped leasehold acreage" means the leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains estimated net proved reserves.

(tt) "Working interest" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

SIGNATURES

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

KODIAK OIL & GAS CORP.
(Registrant)

Date: March 13, 2008

By: /s/ LYNN A. PETERSON

Lynn A. Peterson
President and Chief Executive Officer
(principal executive officer)

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

By:	/s/ LYNN A. PETERSON Lynn A. Peterson	President and Chief Executive Officer (principal executive officer)	March 13, 2008
By:	/s/ JAMES E. CATLIN James E. Catlin	Vice President and Secretary	March 13, 2008
By:	/s/ JAMES P. HENDERSON James P. Henderson	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	March 13, 2008
By:	/s/ HERRICK K. LIDSTONE, JR. Herrick K. Lidstone, Jr.	Director	March 13, 2008
By:	/s/ RODNEY D. KNUTSON Rodney D. Knutson	Director	March 13, 2008
By:	/s/ DON McDONALD Don McDonald	Director	March 13, 2008

CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Lynn A. Peterson
President, Chief Executive Officer and Director

James E. Catlin
Chief Operating Officer and
Chairman of the Board of Directors

James P. Henderson
Chief Financial Officer

Rodney D. Knutson*
Director, Attorney in Aspen, CO

Herrick K. Lidstone, Jr.*
Director , Attorney with Burns, Figa & Will, P. C.

Don A. McDonald, CPA*
Director, Associate with Albrecht & Associates, Inc.

** Member of the Audit, Compensation and Nominating Committees.*

CORPORATE OFFICE

1625 Broadway, Suite 250
Denver, Colorado USA 80202
Tel: 303-592-8075 Fax: 303-592-8071

REGISTERED OFFICE

202-208 Main Street
Whitehorse, Yukon Territory
Y1A 2A9 Canada

AUDITORS

Hein & Associates LLP
Denver, Colorado USA

LEGAL COUNSEL

Dorsey & Whitney LLP
Seattle, Washington USA

Miller Thomson LLP
Vancouver, British Columbia Canada

INDEPENDENT RESERVOIR ENGINEERS

Netherland, Sewell & Associates, Inc.
Dallas, Texas USA

CORPORATE INFORMATION

Stock Exchange Listing
The American Stock Exchange: "KOG"

Registrar and Transfer Agent
Computershare Investor Services, Inc.
Denver, Colorado USA

Contact transfer agent for information regarding changes of address, registration of shares, transfers or lost certificates, or for information about your shareholder account.

Form 10-K
The enclosed Form 10-K of the Company does not include the exhibits that were filed with the U.S. Securities and Exchange Commission. A complete copy of the Form 10-K, including all exhibits, may be obtained by writing to the Company or may be accessed on Kodiak's website at www.kodiakog.com.

Code of Business Conduct and Ethics
Please reference the Corporate Governance section on Kodiak's website at www.kodiakog.com for important information regarding the Company's Code of Business Conduct and Ethics. Additionally, a copy may be obtained by writing to the Company.

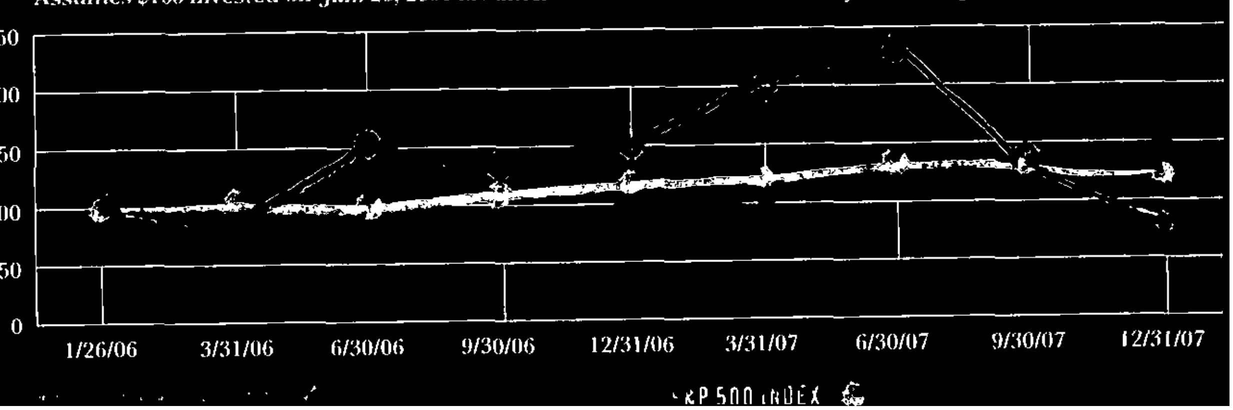
ANNUAL MEETING

Kodiak's annual general meeting will be held at:

The University Club
1673 Sherman Street
Denver, Colorado 80203
Room: Lounge Room
Date: May 22, 2008
Time: 9:00 AM Mountain Daylight Time

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG KODIAK OIL & GAS CORP., S&P 500 INDEX AND XNG INDEX

Assumes $100 invested on Jan. 26, 2006 assumes dividend reinvested fiscal year ending Dec. 31, 2007



KODIAK
OIL & GAS CORP.

1625 Broadway, Suite 250 | Denver, Colorado | USA 80202
Tel: 303-592-8075 | Fax: 303-592-8071
Website: www.kodiakog.com

END