KODIAK

OIL & GAS CORP.

ANNUAL REPORT
2008

Dear Fellow Shareholders:

For Kodiak and our industry, 2008 was marked by unprecedented commodity price volatility, highlighted by oil prices that ranged from July 2008 highs of nearly $150 per barrel to the year-end low of around $35 per barrel. Furthermore, the credit markets experienced turmoil not seen for several decades and severely limited access to capital. We spent 2008 adding core leasehold and obtaining drilling permits in preparation for the fourth quarter delivery of our first Williston Basin drilling rig. A strong land position and multiple drilling permits enabled us to ramp-up our oil and gas activities in 2009.

The economics for crude oil have improved into 2009. As of the date of this letter, we have drilled six wells, completed four wells and expect to complete two more wells in the third quarter of 2009. All of our drilling activity to date in 2009 has targeted the Middle Bakken shale oil play in Dunn County, N.D. Our entire staff has worked diligently to increase our land position, securing the necessary permits that we need for low-risk, development drilling on our leasehold. We are focused on driving down our drilling and completion costs in the play, which should improve with economies of scale in the field as more wells are drilled. We also allocated considerable time and effort in working with mineral owners, the Bureau of Indian Affairs, the Bureau of Land Management and with the Three Affiliated Tribes of the Fort Berthold Indian Reservation (FBIR) in developing a working relationship which the parties believe will help best preserve the quality of life on the FBIR while allowing us to develop the oil reserves.

Production from the four completed wells has greatly improved our cash flow which should continue to improve in future quarters as more wells come on line. Initial production rates and sustained production rates have fallen into the range anticipated prior to drilling the wells. We will continue to evaluate the length of lateral as well as our completion techniques as we move through the 2009 drilling program.

Kodiak feels very strongly about its responsibilities as a good corporate citizen in its operating areas. We value our access to our mineral owners' lands. We also place in high regard our relationships with the Tribal Council and Tribal Members. In working together with the regulatory agencies for a smooth permitting process, we now can go forward with an efficient schedule of development drilling, with minimal surface disturbance. We have few expiry issues with our minerals in the FBIR where the leases are on five-year terms and look forward to continued favorable drill results in 2009 and beyond.

In the fourth quarter of 2008 and in the first two quarters of 2009, Kodiak completed three key transactions to help ensure the Company's viability going forward.

- In November 2008, we announced a seven-well joint venture with a private oil and gas company. The joint venture allows us to vary our working interest in part of our leasehold, effectively managing our capital expenditures to drill more wells across a greater area. Just as we value our mineral-owner and Tribal relations, we are also fortunate to have excellent industry partners with which to operate in the Bakken shale project.
- In May 2009, another pivotal transaction occurred as we closed on $7.15 million equity financing that resulted in the issuance of 9.6 million shares of Kodiak's common stock at $0.75 per share. There were no warrants attached, there was no placement agent and the financing was priced at market. In evaluating our options to secure the necessary capital to continue our 2009 CAPEX program, we considered many financing alternatives, but ultimately determined that the Company and its shareholders would face the minimum amount of dilution through the common stock offering, while allowing us to execute our 2009 plans and preserve our highly prospective leasehold.
- In June 2009, we announced a second transaction, a five-well joint venture with a private oil and gas company that closed the first part of July 2009. The transaction was completed for cash and carried working interests whereby Kodiak maintained operations and an approximate 60% working interest in certain lands in the southeastern part of our FBIR leasehold. Again, this allows us to spread our capital commitments over a greater area and lowers our per-well

exposure. The transaction's net effect reduced our land holdings by approximately 3,300 net acres.

Through careful management of the capital resources available to us, we believe Kodiak is in a sound position to move ahead. The Company is currently debt-free and possesses the capital necessary to complete its 2009 drilling program, assuming the use of one rig throughout the year. We expect to begin layering on additional cash flow as each new successful well is brought on to production. Cash flow is the defining metric of an exploration and production company. With the firming of crude oil prices and the recent reduction in oilfield service costs, we anticipate good cash flow contribution from our Bakken play. While the majority of our effort and capital is going to the Williston Basin, we continue to evaluate our acreage in the Vermillion Basin. Four wells were drilled under an exploration agreement with Devon Energy during 2008. Completion work is currently being reviewed and Kodiak will announce Vermillion activity when definitive plans are made.

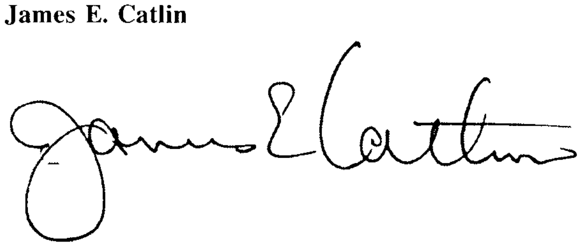
Kodiak continues to focus on cost-cutting measures to maintain general and administrative expense austerity whenever possible. We would also like to note that no appreciable additional overhead is anticipated at Kodiak in the coming months. Our current staff of 16 employees is well-equipped to handle the responsibilities associated with our oilfield activities and in our accounting and administrative functions. Importantly, all of our senior management have endured commodity price cycles in the past and can adroitly manage through the volatility that comes with the cycles. With this in mind, we are intent on investing our capital on hand in drilling and completing wells to grow production, reserves and shareholder value.

We would like to thank our employees and our Board of Directors for their hard work and dedication through what can only be called a roller-coaster 10-month period. Equally important and deserved of sincere thanks are our shareholders, many of who have been supportive, patient and, above all, loyal to Kodiak. We believe our Bakken shale leasehold contains great quantities of recoverable oil and gas that can provide a significant and compelling growth platform for the Company and its shareholders as we look to establish Kodiak as a leading Rockies independent oil and gas company. Please monitor our financial and operational results throughout 2009 so you can properly assess our performance as well as the unfolding development of our Bakken shale resource.

Lynn A. Peterson

President, Chief Executive Officer and Director

James E. Catlin



Chief Operating Officer and Chairman of the Board of Directors

July 10, 2009

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, 2008

Commission file number: 001-32920

KODIAK

OIL & GAS CORP.

(Exact name of registrant as specified in its charter)

Yukon Territory (State or other jurisdiction of incorporation or organization)	**N/A** (I.R.S. Employer Identification No.)
1625 Broadway, Suite 250 **Denver, Colorado 80202** (Address of principal executive offices)	**(303) 592-8075** (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	NYSE Alternext US LLC

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 Form10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" 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, 2008, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $401,665,000.

The number of shares of the registrant's Common Stock outstanding as of March 12, 2009, was 95,129,431.

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, 2009, in connection with the registrant's 2009 Annual Meeting of Shareholders, are incorporated herein by reference into Part III of this Annual Report on Form 10-K.

KODIAK OIL & GAS CORP.
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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.

Current Economic Conditions

The recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of many business operations. The shortage of liquidity and credit combined with recent substantial losses in equity markets has led to a worldwide economic recession. The slowdown in economic activity caused by such recession has reduced worldwide demand for energy resulting in lower oil and natural gas prices. Oil prices declined from record levels in early July 2008 of over $140 per barrel to below $40 per barrel in December 2008, while natural gas prices have declined from over $13 per Mcf to below $6 per Mcf over the same period. In addition, our forecasted prices for 2009 have also declined.

Lower oil and natural gas prices not only decrease our revenues on a per unit basis but also reduce the amount of oil and natural gas that we can produce economically over the life of the wells, and therefore lower our oil and gas reserves recorded in accordance with guidelines established by the Securities and Exchange Commission ("SEC"). A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. Our current working capital and commodity prices received from production are insufficient to fund our 2009 budget, and as a result we will be required to reduce capital spending, issue equity or debt, sell a portion of our properties, enter into additional joint ventures, or access our line of credit. However, lower oil and natural gas prices reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview and Strategy

Kodiak Oil & Gas Corp. ("Kodiak" or the "Company") is 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 primarily concentrated in two Rocky Mountain basins, the Williston Basin of North Dakota and Montana and the Green River Basin of Wyoming and Colorado. Kodiak's 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 development and exploratory drilling opportunities on high potential conventional and non-conventional oil and natural gas prospects, that we have the opportunity to explore, drill and develop. Significant prospects in our portfolio currently include:

- *Eastern Bakken oil play in Mountrail and Dunn Counties, North Dakota:* As of December 2008, we acquired an interest in approximately 52,000 gross (37,000 net) acres in this highly prospective play. We have drilled our first two wells on the prospect acreage and will be completing the wells in the next few months as well completion services become available and winter weather conditions subside.
- *Vermillion Basin of southwest Wyoming:* In the first quarter of 2008, we entered into an exploration and development agreement with Devon Energy Production Company, L.P. ("Devon"), a wholly owned subsidiary of Devon Energy Corp., as part of our strategy to develop this play. As of December 31, 2008, we control approximately 43,000 gross acres and 16,000 net acres in the Vermillion Basin. During the year Devon drilled four wells on the prospect acreage. Completion work is projected for the second half of 2009.

Kodiak Oil & Gas Corp. was incorporated as a company on March 17, 1972 in the Province of British Columbia, Canada, under the name "Pacific Talc Ltd." pursuant to the Company Act (British Columbia). On November 12, 1998, the name of the Company was changed to "Columbia Copper Company Ltd." On September 28, 2001, the Company was continued from British Columbia to the Yukon Territory and the name of the Company was changed to "Kodiak Oil & Gas Corp." On September 23, 2003, we incorporated a wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc. in Colorado. Kodiak Oil & Gas (USA) Inc. was formed to hold all of our US oil and gas properties located in the United States.

For a summary of Kodiak's financial information, including information on loss and total assets, see Item 6—"Selected Consolidated Financial Information."

Williston Basin Operations—Dunn County, North Dakota

In Dunn County, North Dakota, Kodiak's exploration efforts target oil and gas production from the middle member between the upper and lower Bakken shales, which is the source rock for existing hydrocarbons. The Three Forks/Sanish Formation, a productive interval lying directly below the lower Bakken shale, is also expected to be a future exploration target. Commercial production from the Three Forks / Sanish Formation is being reported by operators in the immediate area.

The Moccasin Creek (MC) #16-34-2H well (Kodiak operates with 60% WI and 49% net revenue interest [NRI]) reached total depth in early January 2009. The well, located in the southwestern portion of Kodiak's leasehold, was drilled to an approximate total vertical depth (TVD) of 10,350 feet and a total measured depth (TMD) of 15,525 feet. A liner was run to total depth. The drilling rig was then skid approximately 50 feet where drilling recently finished on the MC #16-34H well (Kodiak operates with 60% WI and 49% NRI). The MC #16-34H reached total depth in February 2009. The well was drilled to a TVD of 10,350 feet and a TMD of 14,810 feet. These two wells were drilled under a letter participation agreement entered into with a private, third-party oil and gas company in November 2008. Under this participation agreement, Kodiak paid 20% of the first wells' drilling costs for its 60% working interest. Drilling costs of the second well drilled were paid in proportion to the non-promoted working interest of each party. Completion work for both the MC#16-34-2H and MC #16-34H is scheduled for the spring of 2009. Completion costs will be paid in the same manner as the drilling costs discussed above.

Approximately 10 miles north of the Moccasin Creek locations, we have spud the Two Shields Butte (TSB) #16-8-16H (Kodiak operates with a 50% WI and a 41% NRI). A second well, the TSB #16-8-7H (Kodiak operates with a 37.5% WI and a 30.5% NRI), is planned to be drilled from this same location. Furthermore, on the Eastern portion of Kodiak's leasehold, we have completed construction of a drilling pad for the Charging Eagle (CE) #1-22-15H and the CE #1-22-24H wells. Upon completion of the TSB #16-8-7H well, we intend to move the drilling rig to the Charging Eagle location.

As of January 1, 2009, Kodiak had approximately 52,000 gross and 37,000 net acres under lease on the Fort Berthold Indian Reservation (FBIR). Kodiak operates all of its leasehold on the FBIR, with the exception of approximately 9,000 net acres that are in a participating area previously established with another operator. As we move through 2009, our capital will be committed to the drilling of wells on the FBIR in North Dakota. As part of this strategy, we have deferred our plans for drilling on other acreage in North Dakota and Montana that are outside the Bakken oil play and on prospect acreage that we have acquired in Wyoming.

Stock Offering

In August 2008, we completed a public offering of 6,000,000 shares of common stock with an exercised over-allotment issuance of an additional 820,000 shares of our common stock at a price of $2.75 per share. Including the exercise of the over-allotment option, the net proceeds of the offering, after deducting underwriting discounts and commissions and our offering expenses, were approximately $17.5 million. We intend to use all of the net proceeds from the offering for exploration and drilling activities.

Revolving Credit Facility

On September 11, 2008, our wholly owned subsidiary, Kodiak Oil & Gas (USA) Inc., entered into a credit facility (the "Credit Facility") with Bank of the West, NA. The Credit Facility is secured by a first priority mortgage and security interest in, among other things, at least 80% of the PV10% value of our existing producing oil and gas properties and producing oil and gas properties hereafter acquired by the Company (including our subsidiaries), all of the stock or partnership interests of all direct or indirect subsidiaries of the Company, and accounts receivable, inventory, contract rights, and general intangibles of the Company (including that of our subsidiaries). As of March 11, 2009 we have not borrowed funds against our Credit Facility. See note 8 to the financial statements included in this Annual Report for more information on the Credit Facility.

Property Acquisition and Exploration Activities

As of December 31, 2008, we had several hundred lease agreements representing approximately 165,000 gross and 98,000 net acres in the Green River and Williston Basins.

In 2008, we increased 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, 2008, we had acquired approximately 52,000 gross acres and 37,000 net acres on the FBIR. Additional acreage has been leased in 2009 or is in the approval process with the Bureau of Indian Affairs ("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 private negotiations 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 FBIR is held primarily on the basis of fee leases. These leases typically carry a primary term of 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 the 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 under which Devon earned a 50% working interest in our leasehold interests in the Vermillion Basin in exchange for, among other things, expenditures that approximate the cost of three horizontally drilled and completed wells. As of the first quarter of 2009, Devon had materially expended the agreed upon amount of capital expenditures and further 2009 expenditures, if any, will be paid in proportion to each parties working interest. 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. The AMI will expire after a period of five years, unless extended by mutual agreement of the parties. Each party has agreed to a proportionate share of any interest or lease acquired within the participating area. Under the terms of the Devon 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.

In November 2008, we entered into a participation agreement with a privately held, third-party oil and gas company on certain lands within the FBIR under which Kodiak has agreed to pay 20% of the first, third, fifth and seventh wells drilling and completion costs for its 60% working interest. The third-party pays 80% of the first, third, fifth and seventh wells drilling and completion costs for its 40% working interest. The second, fourth, and sixth wells on the lands covered under the participation agreement will be drilled in proportion to the working interest of each party. The alternating arrangement of sharing costs for wells drilled under lands covered by the participation agreement will continue through the seventh well, at which time all future wells costs will be shared proportionately to each party's working interest. These wells will be drilled over a 30 month period. In no event will the total promote (costs in excess of the third-party's proportionate share) on the first, third, fifth and seventh wells to be drilled exceed $8.5 million to the third party.

The following table sets forth our gross and net acres of developed and undeveloped oil and natural gas leases as of December 31, 2008.

	Undeveloped Acreage(1)		Developed Acreage(2)		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Green River Basin						
Wyoming(3)	42,692	17,586	1,520	908	44,212	18,494
Colorado	7,419	4,986	0	0	7,419	4,986
Williston Basin						
Montana	33,684	19,770	800	400	34,484	20,170
North Dakota	65,755	43,109	3,040	1,800	68,795	44,909
Other Basins						
Wyoming	12,562	10,875	0	0	12,562	10,875
Acreage Totals	**162,112**	**96,326**	**5,360**	**3,108**	**167,472**	**99,434**

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

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:

	Expiring Acreage	
Year Ending	Gross	Net
December 31, 2009	11,714	5,755
December 31, 2010	31,101	16,607
December 31, 2011	7,791	3,773
Total	50,606	26,135

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 in Wyoming and Colorado 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 $1.4 million and on oil production of $5.4 million and incurred $3.6 million in production costs for the year ended December 31, 2008. Our gas production comes from fifteen wells in the Green River Basin, five of which we operate and ten 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 nine 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,		
	2008	2007	2006
Sales Volume:			
Gas (Mcf)	209,815	200,191	117,324
Oil (Bbls)	63,595	102,914	61,966
Price:			
Gas ($/Mcf)	$ 6.54	$ 5.26	$ 5.56
Oil ($/Bbls)	$ 84.86	$ 65.72	$ 55.52
Production costs ($/BOE):			
Lease operating expenses	$ 28.78	$ 6.87	$ 7.54
Production and property taxes	$ 6.54	$ 5.30	$ 3.95
Gathering, Transportation and Marketing	$ 0.99	$ 0.73	$ 0.34

Capital Expenditures

Our original net capital expenditures were planned to be $15.3 million in 2009 compared to approximately $11.0 million incurred in 2008. We continue to evaluate and monitor our capital expenditures in relation to commodity prices. We anticipate that our expenditures could be less than $15.3 million if current economic conditions continue throughout 2009.

We had working capital of $15.4 million inclusive of cash and cash equivalents of $7.6 million as of December 31, 2008. Our working capital included $6.5 million of prepaid tubular goods for the first six wells of our 2009 drilling program, which have been reported as prepaid expenses as we have not taken physical delivery of the goods as of December 31, 2008. These costs will be applied to our share of the drilling costs for the first six wells, or will be recovered from our drilling partners. Based on our original 2009 drilling and exploration program, the Company anticipated that our 2009 capital expenditures in the Williston Basin would be approximately $11.3 million. While we cannot fully assess our capital expenditures or the timing of expenditures in the Vermillion Basin as we do not operate the properties, we anticipate that two of the wells that were horizontally drilled during 2008 could be completed during 2009. These costs cannot be determined at this time due to the uncertainty of commodity prices and expenditures. We estimated that our share of the completion costs would not exceed $4.0 million.

Due to current capital and credit market conditions, we cannot be certain that funding will be available to us in amounts or on terms acceptable to the Company. Our current cash balances and cash flow from operations will not alone be sufficient to provide working capital to fully fund our original 2009 plan of operations. Accordingly, we intend to pursue alternatives, such as joint ventures with third parties or sales of interest in one or more of our properties. Such transactions may result in a reduction in our operating interests or require us to relinquish the right to operate the property. There can be no assurance that any such transactions can be completed or that such transactions will satisfy our operating capital requirements. If we are not successful in obtaining sufficient funding or completing an alternative transaction on a timely basis on terms acceptable to us, we would be required to curtail our expenditures or restructure our operations, and we would be unable to implement our original exploration and drilling program, either of which would have a material adverse effect on our business, financial condition and results of operations.

The following tables set forth our capital expenditures for the year ended December 31, 2008 and, subject to the availability of capital, our maximum capital expenditures for our principal properties in 2009. Net capital expenditures include both cash expenditures and accrued expenditures and are net of proceeds from divestitures.

Project Location	2008 Net Capital Expenditures ($000)	2009 Estimated Net Capital Expenditures ($000)
Wyoming		
Vermillion Basin wells and related infrastructure	$ 517	$ 4,000
Other Wyoming wells and related infrastructure	67	—
Acreage/Seismic	401	—
Total Wyoming	$ 985	$ 4,000
Williston Basin		
Mission Canyon/Red River wells and related infrastructure	168	700
Bakken wells and related infrastructure	2,397	10,055
Acreage/Seismic	7,506	500
Total Williston Basin	$10,071	$11,255
Total All Areas	$11,056	$15,255

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, 2008, 2007 and 2006. In addition, as of December 31, 2008, we have four gross (1.95 net) non operated wells in progress and one gross (0.6 net) operated well in progress.

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Oil wells	—	—	2	1.0	3	1.9
Gas wells	1	0.1	—	—	3	1.5
Non-Productive(1)	—	—	1	0.5	—	—
Exploratory wells, completed as:						
Oil wells	—	—	—	—	—	—
Gas wells	—	—	3	2.8	2	2.0
Non-Productive(1)	—	—	4	1.8	1	0.5
Total	**1**	**0.1**	**10**	**6.1**	**9**	**5.9**

(1) A non-productive well (also known as a dry hole) 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.

During the second quarter of 2008, the Company entered into two-year contracts for the use of two new-build drilling rigs. The first rig was placed into operation in November 2008 under an agreement which provides for a two year drilling commitment or specific termination fees if drilling activity is cancelled. The terms of that agreement require utilization of the rig and payment of day rates or the payment of standby rates if the rig is not utilized. The estimated termination fee for the first rig is approximately $5.3 million as of December 31, 2008. The termination fee on the first rig will continue to decrease as long as we keep the rig active. The second rig has not yet been delivered, and we are negotiating with the rig contractor to either cancel or delay our obligation with respect to the second rig and avoid all or a part of the potential contractual $5.6 million cancellation penalty. We cannot offer any assurance that we will be able to negotiate a satisfactory resolution to this issue. Both we and the rig owner are attempting to find another company that will take over our obligations, although there can be no assurance that we will be able to do so.

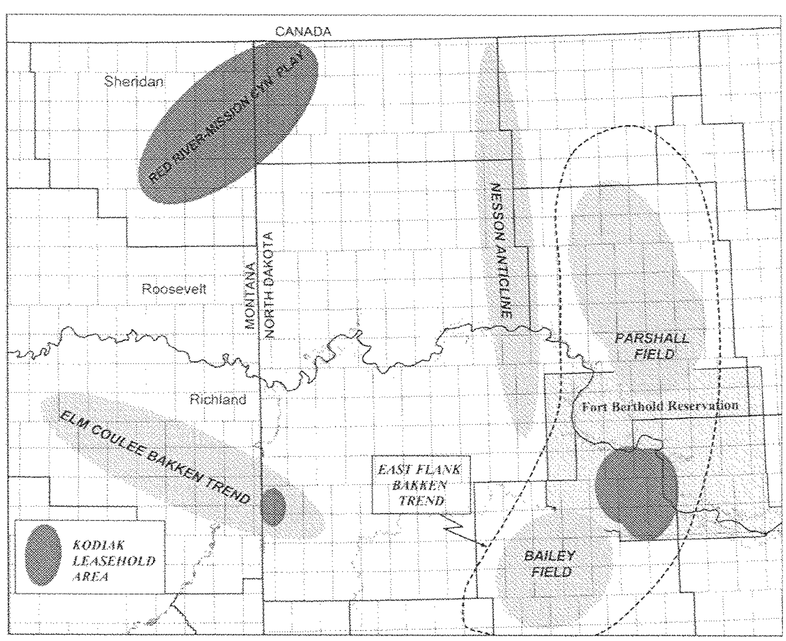
Productive Wells

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, 2008, 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	5	4.7	10	4.2	15	8.9
Total	**14**	**9.4**	**10**	**4.2**	**24**	**13.6**

Operations in the Williston Basin of Montana and North Dakota

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



Bakken Formation—Dunn and McKenzie Counties, North Dakota

We have continued our exploration activity in Dunn County, North Dakota where the primary objective is the dolomitic, sandy interval between the two Bakken Shales at an approximate vertical depth of 10,000 feet, and the Three Forks Formation that is present immediately below the lower Bakken Shale. As of December 31, 2008, we had acquired approximately 52,000 gross acres and 37,000 net acres on the FBIR. We have completed the drilling of two wells in this area and are currently drilling a third well. The wells have been drilled on 320 acre drilling blocks with approximate 4,500 foot laterals in the middle Bakken interval. The wells will be completed in the coming months as services become available and the winter weather subsides. We intend to participate in up to nine additional wells in the area during 2009 where Kodiak will be the operator. Drilling and completion plans will be varied during the year. We anticipate drilling some of the wells on 1,280 acre drilling blocks; lay-down our stand-up 640 acre drilling blocks; and some on 320 acre drilling blocks. The 1,280 acre and 640 acre blocks will allow drilling of nearly 10,000 foot laterals while the 320 acre blocks allow us to drill approximate 4,500 foot laterals. Some of the wells could be drilled in the Three Forks Formation as additional production data is obtained from wells currently producing or drilling by other operators. Completion techniques will also be evaluated during the year with the expectation of developing plans as more data becomes available.

Kodiak has three wells (two producing) in McKenzie County producing from the Bakken Formation near the North Dakota and Montana state line. Based on economic conditions at year end 2008, all undeveloped locations in this area, even though they are located on lands held by the producing wells, were considered uneconomic and removed from our proved undeveloped reserve classification.

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 2008, Kodiak completed the acquisition of an approximate 18 square mile 3-D seismic program over a portion of this acreage. The seismic defined closure on two Red River prospects that we would expect to drill in 2009, subject to economic conditions and adequate capital.

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, 2008, we controlled approximately 43,000 gross (16,000 net) acres.

Devon commenced drilling operations in August 2008 and has drilled four wells to date. The intent of the 2008 drilling program was to obtain and evaluate data points from different locations within our acreage block.

2008 exploration efforts were focused on two specific areas: the Horseshoe Basin Unit (HBU) located on the western edge of Kodiak's acreage and the Coyote Flats Federal Unit (CFU) located on the northern edge. Kodiak has an approximate 50% working interest in the following wells

- The CFU #1-8 well was drilled to an approximate depth of 12,750 feet in the Baxter shale and extensive logging procedures were completed. After evaluation of all data this well may be drilled horizontally (depending on economic conditions).

- The HBU #1-4 well was drilled to a vertical depth of approximately 11,700 feet and approximately 240 feet was cored in the target pay zones. Current exploration plans anticipate that this well may be reentered at a later date (depending on economic conditions) and drilled horizontally through the targeted Baxter interval.
- The HBU #13-36 well was drilled to an approximate vertical depth of 14,300 feet and 4,100 feet horizontally. Production liner was run into the lateral well bore. Completion work on this well will be scheduled subject to economic conditions.
- The CFU #14-36 well was drilled to an approximate vertical depth of 15,300 feet and 4,800 feet horizontally. Production liner was run into the lateral well bore. Completion work on this well will be scheduled subject to economic conditions.
- The gathering pipeline and facilities were installed and began operations in November 2008, connecting the HBU #5-3 well to production.
- Acquisition of approximately 25 square miles of 3-D seismic was completed over a portion of the Horseshoe Basin Unit. This data is presently being evaluated.

Kodiak's operated wells in the Vermillion Basin were shut in during November 2008 due to adverse Rockies gas prices. The wells continue to be shut-in pending improvement in natural gas pricing, for which we cannot offer any assurance.

Our Reserves

All of our reserves are located within the continental United States. Netherland Sewell & Associates, Inc. ("Netherland"), a petroleum engineering consulting firm, prepared our estimated reserves as of December 31, 2008. Netherland audited our estimated reserves as of December 31, 2007. We understand that the work by Netherland was conducted in accordance with the principles set forth in the Society of Petroleum Engineers audit standards and in compliance with the Commission reserves classifications and definitions set out in Rule 4-10 of Regulation S-X. We have been advised that Netherland's audit consisted primarily of substantive testing, wherein Netherland conducted a detailed review of all of our properties.

The Company's engagement of Netherland in 2007 contemplated that Netherland would audit 100% of the Company's reserves, and the Company did not place any limitations on Netherland in the conduct of Netherland's audit. The Company is not aware of the actual percentage of the Company's reserves audited by Netherland. We are not aware of any assumptions provided by management that were relied upon by Netherland without testing. The engagement of Netherland was authorized by the Board of Directors. Netherland reported to the management of the Company.

A reserves audit and a financial audit are separate activities with unique and different processes and results. These two activities should not be confused. As currently defined by the Society of Petroleum Engineers, a reserves audit should be of sufficient rigor to determine the appropriate reserves classification for all reserves in the property set evaluated and to clearly state the reserves classification system being utilized. In contrast, a financial audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

The reserve estimates as of December 31, 2007 were developed using geological and engineering data and interests and burdens information developed by our Company. Netherland prepared our estimated reserves as of December 31, 2008 and December 31, 2006. 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, 2008 and 2007 included elsewhere in this Form 10-K in conjunction with the following reserve estimates:

	As of December 31,	
	2008	2007
Proved Developed Oil Reserves (Thousands of Barrels, or MBbls)	344.4	623.9
Proved Undeveloped Oil Reserves (MBbls)	—	308.1
Total Proved Oil Reserves (MBbls)	344.4	932.0
Proved Developed Gas Reserves (Million Cubic Feet, or MMcf)	1,218.0	2,455.7
Proved Undeveloped Gas Reserves (MMcf)	—	240.5
Total Proved Gas Reserves (MMcf)	1,218.0	2,696.2
Total Proved Gas Equivalents (Million Cubic Feet Equivalent, or MMcfe)(1)	3,284.4	8,287.0
Total Proved Oil Equivalents (Thousands of Barrels Equivalent, or MBOE)(1)	547.4	1,381.2
Present Value of Estimated Future Net Revenues After Income Taxes, Discounted at 10%(3)	$5,328.1	$36,194.2

(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, 2008 and 2007 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, 2008 and 2007 were $3.76 and $6.97 per Mcf and $24.09 and $81.30 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 2008 or 2007 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, 2008 and 2007.

As of December 31, 2008, based on our net oil and gas prices of $24.09 per barrel of crude oil and $3.76 per Mcf of natural gas, the value of Kodiak's proved reserves as calculated under SEC guidelines did not support the costs included in the full cost pool. Additionally, we evaluated our existing unproved properties and determined that approximately $17.2 million of our unproved properties were impaired as of December 31, 2008. Due to our current capital constraints, we impaired all leases expiring in 2009 since our existing capital is allocated to our Eastern Bakken play in Dunn County, North Dakota and the lack of capital in the industry to support drilling activity through farmouts. Therefore we reclassified this amount to our full cost pool prior to conducting our year-end 2008 ceiling test. Due to lower prices, the above mentioned asset impairment, and a revision of our previously recorded proved undeveloped locations (PUD) caused by lower commodity prices and timing of projected drilling, the Company recorded a write-down of $32.0 million during the fourth quarter of 2008. This write-down is in addition to a $15.5 million impairment charge recorded during the quarter ended September 30, 2008 bringing the full year 2008 impairment charge to $47.5 million.

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. With the recent decline in crude oil and natural gas prices, access to additional drilling equipment is currently more available.

Commodity Price Environment

Generally, the demand for and the price of natural gas increases during the colder winter months and decreases 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.

During the first half of 2008, the prices received for domestic production of oil and natural gas increased significantly, which resulted in increased demand for the equipment and services that we require to drill, complete and operate wells. As a result of this increased demand for oil field services, shortages developed from 2007 into 2008, leading to an escalation in drilling rig rates, field service costs, material prices and all costs associated with drilling, completing and operating wells through the first half of 2008. Since July 2008, crude oil and natural gas prices have fallen from record highs of approximately $140 per barrel to below $40 per barrel. We have noted a decline in certain costs in relation to the lower price of crude oil. If oil and natural gas prices remain low relative to historical levels or go lower, we anticipate that the recent trends toward decreasing costs and more available equipment 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 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, 2008, we employed seventeen 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 Annual Report on Form 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 Exchange Act, are available on our website as soon as reasonably practicable after we electronically file such reports with, or furnish those reports to, the SEC.

We maintain a Code of Business Conduct and Ethics for Directors, Officers and Employees ("Code of Conduct"). A copy of our Code of Conduct may be found on our website in the Corporate Governance section. Our Code of Conduct 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 have a recent history of negative reserve revisions.

We have a recent history of negative reserve revisions that occurred during the current year and during the last two fiscal years. Specifically, our December 31, 2008 oil and natural gas reserves reflected a downward revision of the December 31, 2007 reserves in the amount of approximately 833.8 BOE primarily as a result of both the significantly lower year-end crude oil and natural gas prices as of December 31, 2008 versus December 31, 2007 and the revision of reserves associated with proven undeveloped reserves. Our December 31, 2007 natural gas reserves reflected a downward revision of the December 31, 2006 reserves in the amount of 1.1 BCF, primarily as a result of the revision of reserves associated with the underperformance of one Vermillion Basin exploratory well. Our December 31, 2006 natural gas reserves reflected a downward revision of the December 31, 2005 reserves of 2.8 BCF, primarily as a result of the revision of reserves associated with our decision to discontinue exploration and development of our coalbed methane 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, negative reserve revisions in the future may also 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. When reserves are found to be materially lower than we had estimated and reported, our prospects and stock price could be adversely affected.

Our working capital will not be sufficient to support all of our planned exploration opportunities in 2009.

We had working capital of $15.4 million inclusive of cash and cash equivalents of $7.6 million as of December 31, 2008. Our working capital included $6.5 million of prepaid tubular goods for the first six wells of our 2009 drilling program, which have been reported as prepaid expenses as we have not taken physical delivery of the goods as of December 31, 2008. These costs will be applied to our share of the drilling costs for the first six wells, or will be recovered from our drilling partners. Based on our original 2009 drilling and exploration program, the Company anticipated that our 2009 capital expenditures in the Williston Basin would be approximately $11.3 million. While we cannot fully assess our capital expenditures or the timing of expenditures in the Vermillion Basin as we do not operate the properties, we anticipate that two of the wells that were horizontally drilled during 2008 could be completed during 2009. These costs cannot be determined at this time due to the uncertainty of commodity prices and expenditures. We estimated that our share of the completion costs would not exceed $4.0 million.

Due to current capital and credit market conditions, we cannot be certain that funding will be available to us in amounts or on terms acceptable to the Company. Our current cash balances and cash flow from operations will not alone be sufficient to provide working capital to fully fund our original 2009 plan of operations. Accordingly, we intend to pursue alternatives, such as joint ventures with third parties or sales of interest in one or more of our properties. Such transactions may result in a reduction in our operating interests or require us to relinquish the right to operate the property. There can be no assurance that any such transactions can be completed or that such transactions will satisfy our operating capital requirements. If we are not successful in obtaining sufficient funding or completing an alternative transaction on a timely basis on terms acceptable to us, we would be required to curtail our expenditures or restructure our operations, and we would be unable to implement our original exploration and drilling program, either of which would have a material adverse effect on our business, financial condition and results of operations.

If we borrow funds, we will be obligated to make periodic interest or other debt service payments and may be subject to additional restrictive covenants. The ability to borrow 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 may incur termination fees related to two drilling rig contracts that we entered into in 2008 which could impair our working capital.

During the second quarter of 2008, the Company entered into two-year contracts for the use of two new-build drilling rigs. The first rig was placed into operation in November 2008 and entails a two year drilling commitment or specific termination fees if drilling activity is cancelled. The estimated termination fee for the first rig is approximately $5.3 million as of December 31, 2008. The termination fee on the first rig will continue to decrease so long as we keep the rig active. Our second rig has been placed on hold with the drilling contractor. We are negotiating with the rig contractor to either cancel or delay our obligation with respect to the second rig and avoid all or a part of the contractual $5.6 million cancellation penalty. We cannot offer any assurance that we will be able to negotiate a satisfactory resolution to this issue. Both we and the rig owner are attempting to find another company that will take over our obligations, although there can be no assurance that we will be able to do so. If we incur these fees by terminating the drilling rigs, our working capital could be impaired, which would accelerate the need we may have for additional capital funding.

The deterioration of global economic and financial conditions and an extended decline in the price of oil and natural gas could negatively impact our business, financial condition and results of operations.

The current global economic and financial crisis could lead to an extended national or global economic recession. A slowdown in economic activity caused by a recession would likely reduce national and worldwide demand for oil and natural gas and result in lower commodity prices. Substantial decreases in oil and natural gas prices could have a material adverse effect on our business, financial condition and results of operations, could limit our liquidity and credit-worthiness and could hinder our ability to fund our development program. The inability to execute our development program could also lead to low production and reserve growth. In addition, current economic conditions could harm the liquidity or financial position of our partners or suppliers, which could, in turn, cause such parties to fail to meet their contractual or other obligations to us.

If credit and capital markets worsen, then we may not be able to obtain funding on acceptable terms. The inability to obtain funding could deter or prevent us from meeting our future capital needs to fund our capital expenditure program.

Capital and credit markets have experienced unprecedented volatility and disruption during the last half of 2008 and continue to be unpredictable. Given the current levels of market volatility and disruption, the availability of funds from those markets has diminished substantially. Further, arising from concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of accessing the credit markets has increased as many lenders have raised interest rates, enacted tighter lending standards or altogether ceased to provide funding to borrowers. Additionally, even if lenders continue and are able to provide funding to borrowers, interest rates may rise in the future and therefore increase the cost of outstanding borrowings that we may incur under our revolving Credit Facility.

Moreover, we may be unable to obtain adequate funding under our current Credit Facility. Our borrowing base under our current Credit Facility is redetermined semi-annually. Our lenders have substantial ability to reduce our borrowing base on the basis of, among other things, subjective factors. If oil and natural gas prices significantly decline for an extended period of time, our lenders could redetermine the borrowing base by evaluating our reserves at substantially lower oil and natural gas prices. Such determination could result in a negative revision to our proved reserve value and reduce our borrowing base.

Due to these capital and credit market conditions, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or may be required to post collateral to support our obligations, or we may be unable to implement our capital expenditure program, grow our existing business through acquisitions or joint ventures or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our business, financial condition and results of operations.

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, 2008, we had a cumulative deficit of $103.3 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.

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, 2008 reserve estimate was prepared by Netherland Sewell & Associates, Inc. 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, 2008, we owned a non-operating interest in ten 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.

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.

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. 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 Doss 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 SEC require us to include this assessment and opinion in this annual report for our fiscal year ended December 31, 2008.

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.

Risks Relating to Our Common Stock

Future sales or other issuances of our common stock could depress the market for our common stock.

On July 14, 2008, we filed a shelf registration statement on Form S-3 (SEC file No. 333-152311), which was declared effective by the SEC on July 24, 2008. Under this shelf registration statement, we have raised funds and may seek to raise additional funds through one or more public offerings of our common stock, in amounts and at prices and terms determined at the time of the offering. Any sales of large quantities of our common stock could reduce the price of our common stock, and, to the extent that we raise additional capital by issuing equity securities pursuant to our effective shelf registration statements or otherwise, our existing stockholders' ownership will be diluted. In August 2008, the Company issued 6,820,000 shares of common stock in a public offering for gross proceeds of approximately $18.8 million. The Company paid approximately $1.3 million in commissions and expenses.

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

Our common stock has been trading on the NYSE Alternext US LLC (formerly the American Stock Exchange, or AMEX) ("NYSE Alternext US"), since June 21, 2006. Prior to listing on the NYSE Alternext US, 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. In 2008, we issued 6,820,000 shares of our common stock for net proceeds of $17,471,488. 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 NYSE Alternext US (formerly 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.

Period Ended	NYSE Alternext US High	NYSE Alternext US Low
December 31, 2008	$1.55	$0.29
September 30, 2008	$4.84	$1.11
June 30, 2008	$5.50	$1.57
March 31, 2008	$2.63	$1.56
December 31, 2007	$3.60	$1.54
September 30, 2007	$5.85	$3.10
June 30, 2007	$6.81	$4.75
March 31, 2007	$5.79	$3.57

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 1,395,499 stock options (net of exercises, cancellations and forfeitures) and 4,000 shares (net of cancellations and forfeitures) of restricted stock in 2008. As of December 31, 2008, the Company has outstanding options to purchase 7,507,499 common shares at prices ranging from $0.36 to $6.26.

Equity Compensation Plan Information as of December 31, 2008

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	7,507,499(1)	$2.87	431,501
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	7,507,499(1)	$2.87	431,501

(1) Excludes 24,000 shares of restricted stock granted in 2008.

As of December 31, 2008 and December 31, 2007, the number of unoptioned shares available for granting of stock options under the Company's 2007 Stock Incentive Plan was 431,501 and 1,807,000, respectively. During the fiscal years ended December 31, 2008 and December 31, 2007, the Company made no changes to the exercise price of outstanding options through cancellation and reissuance or otherwise.

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.

Certain 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 by attribution) 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" (or "PFIC", as defined below) 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) certain holding period requirements are met.

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 PFIC 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 PFIC for the taxable year ended December 31, 2008, and based on current business plans and financial projections; the Company does not expect that it will be a PFIC for the taxable year ending December 31, 2009. (See more detailed discussion at "Passive Foreign Investment Company Rules" below). However, 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 will not be a PFIC 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 PFIC, but a U.S. Holder does not otherwise qualify for the preferential tax rate discussed above, 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.

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), which generally would be treated as U.S. source income or loss for foreign tax credit purposes.

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 PFIC 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.

The amount realized by a U.S. Holder receiving foreign currency in connection with a disposition of Common Shares generally will be equal to the U.S. dollar value of the proceeds received based on the exchange rate applicable on the date of receipt. A U.S. Holder that does not convert foreign currency received 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), which generally would be treated as U.S. source income or loss for foreign tax credit purposes.

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.

Passive Foreign Investment Company Rules

If the Company were to constitute a PFIC (as defined below) for any year during a U.S. Holder's holding period, then certain different and potentially adverse tax consequences would apply to such U.S. Holder's acquisition, ownership and disposition of Common Shares.

The Company generally will be a PFIC under Section 1297 of the Code 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) 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). "Gross income" generally means all revenues less the cost of goods sold, and "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. Active business gains arising from the sale of commodities generally are excluded from passive income if substantially all of a foreign corporation's commodities are (a) stock in trade of such foreign corporation or other property of a kind which would properly be included in inventory of such foreign corporation, or property held by such foreign corporation primarily for sale to customers in the ordinary course of business, (b) property used in the trade or business of such foreign corporation 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 such foreign corporation in the ordinary course of its trade or business.

In addition, 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 foreign corporation, the Company will be treated as if it (a) held a proportionate share of the assets of such other foreign corporation and (b) received directly a proportionate share of the income of such other foreign 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.

Under certain attribution rules, if the Company is a PFIC, U.S. Holders will be deemed to own their proportionate share of any subsidiary of the Company which is also a PFIC (a "Subsidiary PFIC"), and will be subject to U.S. federal income tax on (i) a distribution on the shares of a Subsidiary PFIC or (ii) a disposition of shares of a Subsidiary PFIC, both as if the holder directly held the shares of such Subsidiary PFIC.

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 2008, and does not expect that it will be a PFIC for the taxable year ending 2009. However, PFIC classification is fundamentally factual in nature, generally cannot be determined until the close of the taxable year in question, and is determined annually. Consequently, there can be no assurance that the Company has never been and will not become a PFIC for any taxable year during which U.S. Holders hold Common Shares.

Under the default PFIC rules, a U.S. Holder would be required to treat any gain recognized upon a sale or disposition of the Common Shares as ordinary (rather than capital), and any resulting U.S. federal income tax may be increased by an interest charge which is not deductible by non-corporate U.S. Holders. Rules similar to those applicable to dispositions will generally apply to distributions in respect of Common Shares which exceed a certain threshold level.

While there are U.S. federal income tax elections that sometimes can be made to mitigate these adverse tax consequences (including, without limitation, the "QEF Election" and the "Mark-to-Market

Election"), such elections are available in limited circumstances and must be made in a timely manner. U.S. Holders are urged to consult their own tax advisers regarding the potential application of the PFIC rules to the ownership and disposition of Common Shares, and the availability of certain U.S. tax elections under the PFIC rules.

U.S. Holders should be aware that, for each taxable year, if any, that the Company or any Subsidiary PFIC is a PFIC, the Company can provide no assurances that it will satisfy the record keeping requirements of a PFIC, or that it will make available to U.S. Holders the information such U.S. Holders require to make a QEF Election under Section 1295 of the Code with respect of the Company or any Subsidiary PFIC. Each U.S. Holder should consult its own tax advisor regarding the availability of, and procedure for making, a QEF Election with respect to the Company and any Subsidiary PFIC.

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, 2008, 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

On July 14, 2008, we filed a shelf registration statement on Form S-3 (SEC File No. 333-152311), which was declared effective by the SEC on July 24, 2008. Under this shelf registration statement, we have raised funds through a public offering of our common stock. In August 2008, the Company issued 6,820,000 shares of common stock in a public offering for gross proceeds of approximately $18.8 million. The Company paid approximately $1.3 million in commissions and expenses. We intend to use all of the net proceeds from the offering for exploration and drilling activities.

Issuer Purchases of Equity Securities

During the fiscal year ended December 31, 2008, neither the Company nor any affiliated purchaser purchased any of the Company's 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, 2008, 2007, 2006, 2005, and 2004. The data as of and for the fiscal years ended December 31, 2008, 2007, and 2006 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. Also see "Recently Adopted Accounting Pronouncements" included in the notes to the consolidated financial statements included elsewhere in this Form 10-K.

	For the Years Ended December 31,				
	2008	2007	2006	2005	2004
Income Statement Data:					
Revenue	$ 6,964,790	$ 9,230,377	$ 4,965,169	$ 453,135	$ 20,448
Cost and expenses, excluding impairment	15,962,854	13,506,267	7,751,209	2,458,226	1,082,548
Asset impairment	47,500,000	34,000,000	—	—	—
Net loss	(56,498,064)	(38,185,890)	(2,786,040)	(2,005,091)	(1,062,100)
Basic and diluted net loss per common share	$ (0.62)	$ (0.44)	$ (0.04)	$ (0.05)	$ (0.04)
Adjusted EBITDA (see below reconciliation)	$ (1,237,829)	$ 2,680,565	$ 947,247	$(1,210,248)	$ (705,765)

(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.

	For the Years Ended December 31,				
	2008	2007	2006	2005	2004
Balance Sheet Data:					
Current assets	$20,654,933	$15,377,809	$ 61,117,145	$ 7,990,556	$ 2,756,745
Property and equipment, net	17,842,773	58,386,427	52,250,265	17,463,269	2,450,741
Total assets	39,016,479	74,331,321	113,773,614	25,790,316	5,207,486
Current liabilities	5,231,075	5,163,457	9,879,104	4,411,572	369,008
Stockholders' equity	$32,998,224	$68,293,366	$103,644,815	$21,309,671	$ 4,838,478
Basic and diluted weighted-average common shares outstanding	90,739,316	87,742,996	71,425,243	44,447,269	27,696,443

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:

	For the Years Ended December 31,				
	2008	2007	2006	2005	2004
EBITDA Reconciliation:					
Net Loss	$(56,498,064)	$(38,185,890)	$(2,786,040)	$(2,005,091)	$(1,062,100)
Add back:					
Depreciation, depletion, amortization and accretion	4,172,077	5,206,631	2,173,918	157,868	13,671
Asset impairment	47,500,000	34,000,000	—	—	—
(Gain) / loss on foreign currency exchange	36,725	(792,467)	32,008	95,864	(68,574)
Stock based compensation expense	3,551,433	2,452,291	1,527,361	541,111	411,238
Adjusted EBITDA	(1,237,829)	2,680,565	947,247	(1,210,248)	(705,765)

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 Consolidated Financial Information" in Item 6 above and our historical consolidated financial statements and the accompanying notes.

Overview and 2008 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 2008, we invested capital of $11.0 million in our oil and gas operations including $3.2 million spent on drilling, completion and related infrastructure and $7.8 million spent on land leasing and geological and geophysical data. Our original net capital expenditures were planned to be $15.3 million in 2009; please see the section "Liquidity and Capital Resources" below for further information. 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 acreage position acquired in 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, although because of a national decline in oil and gas prices and oil and gas exploration activity in this area has generally slowed down. Although during 2008 we continued to expand our acreage position in Dunn County, North Dakota, we are presently very selective on acreage acquisitions, with leasing activity involving mostly small parcels which fill in our acreage block.

The Moccasin Creek (MC) #16-34-2H well (Kodiak operates with 60% WI and 49% net revenue interest [NRI]) reached total depth in early January 2009. The well, located in the southwestern portion of Kodiak's leasehold, was drilled to an approximate total vertical depth (TVD) of 10,350 feet and a total measured depth (TMD) of 15,525 feet. A liner was run to total depth. The drilling rig was then skid approximately 50 feet where drilling recently finished on the MC #16-34H well (Kodiak operates with 60% WI and 49% NRI). The MC #16-34H reached total depth in early February 2009. The well was drilled to a TVD of 10,350 feet and a TMD of 14,810 feet. These two wells were drilled under a participation agreement entered into with a private, third-party oil and gas company in November 2008. Under this participation agreement, Kodiak paid 20% of the first wells' drilling costs for its 60% working interest (WI). Drilling costs of the second well drilled were paid in proportion to the non-promoted working interest of each party. Completion work for both the MC#16-34-2H and MC #16-34H is scheduled for the spring of 2009. Completion costs will be paid in the same manner as the drilling costs discussed above.

As of December 31, 2008, we had estimated proved reserves of 1.2 billion cubic feet ("BCF") of natural gas and 344 thousand barrels ("MBbls") of oil with a present value discounted at 10% of $5.2 million. Our reserves are 100% proved developed and are comprised of 37% natural gas and 63% crude oil on an energy equivalent basis. Our December 31, 2008, reserves reflect a downward revision of the December 31, 2007, reserves of 833.8 BOE, primarily related to a change in commodity prices, and a revision of our previously recorded proved undeveloped locations (PUD)

We had gas sales in 2008 of 573 Mcf per day and crude oil sales of 174 barrels per day. This was an increase of 4.8% for gas sales and 38.2% decrease for oil sales over the volumes sold in 2007. During 2008, our revenues from oil and gas sales decreased by $1.0 million or 13% to $6.8 million. Lower sales volumes accounted for $3.2 million of the decline, partially offset by a positive effect of $2.2 million, due to increased prices in 2008 versus 2007. Total oil and gas production expenses increased 104% to $3.6 million in 2008 from $1.8 million in 2007. Of the $1.8 million increase in 2008, $1.7 million is attributed to well workover operations charged to expense during the year.

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 2008 and into 2009, we have seen significant volatility in oil and natural gas prices. The recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets has lead to a worldwide economic recession. The slowdown in economic activity caused by such recession has reduced worldwide demand for energy and resulted in lower oil and natural gas prices. Oil prices declined from record levels in early July 2008 of over $140 per Bbl to below $40 per Bbl in December 2008, while natural gas prices have declined from over $13 per Mcf to below $6 per Mcf over the same period. In addition, our forecasted prices for 2009 have also declined. We believe that spot market prices reflect worldwide concerns about the global economy, producers' ability to ensure sufficient supply to meet increasing demand amid a host of uncertainties caused by political instability, a fluctuating 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 2008, we experienced record crude oil prices in the Williston Basin 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 $84.86 per barrel versus $65.72 per barrel in 2007, while our average gas price received was $6.54 per Mcf compared to $5.26 per Mcf in 2007.

In 2008, our financial position and results of operations were affected significantly by an asset impairment related to the carrying value of our developed properties. During 2008, we incurred capital expenditures of approximately $11.0 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 quarterly throughout the year did not exceed the costs included in the full cost pool. Consequently the Company recorded a cumulative asset impairment of $47.5 million during 2008.

Outlook

Our 2009 activities will be subject to two significant factors—(i) oil and natural gas prices coupled with the cost of exploration and development activities, and (ii) our available working capital and ability to pay for or finance proposed activities. Subject to those issues, in 2009, we expect to continue a multiple well drilling program in our Eastern Bakken play in Dunn County, North Dakota. We have projected as many as nine additional wells that we could participate in during 2009 subject to economic conditions and drilling results, although currently we do not have the resources necessary to complete these activities. This number could be decreased if the current commodity environment persists throughout the year or if we are unable to pay our share of the operations. In the Vermillion Basin our activity will be significantly influenced by gas prices and we do not expect much activity in 2009. As the majority of our acreage is held within Federal Units we are obligated to only spend limited capital during the year.

The current global economic and financial crisis could lead to an extended national or global economic recession. A slowdown in economic activity caused by an extended recession would likely reduce national and worldwide demand for oil and natural gas and result in lower commodity prices. Substantial decreases in oil and natural gas prices could have a material adverse effect on our business, financial condition and results of operations, could further limit our access to liquidity and credit and could hinder our ability to satisfy our capital requirements.

Capital and credit markets have experienced unprecedented volatility and disruption during the last half of 2008 and continue to be unpredictable. Given the current levels of market volatility and disruption, the availability of funds from those markets has diminished substantially. Further, arising from concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of accessing the credit markets has increased as many lenders have raised interest rates, enacted tighter lending standards or altogether ceased to provide funding to borrowers.

Due to current capital and credit market conditions, we cannot be certain that funding will be available to us in amounts or on terms acceptable to the Company. Our current cash balances and cash flow from operations will not alone be sufficient to provide working capital to fully fund our original 2009 plan of operations. Accordingly, we intend to pursue alternatives, such as joint ventures with third parties or sales of interest in one or more of our properties. Such transactions may result in a reduction in our operating interests or require us to relinquish the right to operate the property. There can be no assurance that any such transactions can be completed or that such transactions will satisfy our operating capital requirements. If we are not successful in obtaining sufficient funding or completing an alternative transaction on a timely basis on terms acceptable to us, we would be required to curtail our expenditures or restructure our operations, and we would be unable to implement our original exploration and drilling program, either of which would have a material adverse effect on our business, financial condition and results of operations.

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, 2008, we had working capital of $15.4 million as compared to $10.2 million at December 31, 2007, and no outstanding long-term debt.

The following table summarizes our sources and uses of cash for each of the three years ended December 31, 2008, 2007 and 2006.

	For the years ended ended December 31,		
	2008	**2007**	**2006**
Capital Resources and Liquidity			
Cash and cash equivalents at end of the period	$ 7,581,265	$ 13,015,318	$ 58,469,263
Net cash provided by (used in) operating activities	(2,174,519)	2,073,412	3,141,149
Net cash used in investing activities	(20,911,023)	(47,909,507)	(35,551,258)
Net cash provided by financing activities	17,651,489	382,150	83,593,824
Net cash flow	(5,434,053)	(45,453,945)	51,183,715

The decrease in cash provided by operations from 2007 to 2008 is primarily from our workover activities on three wells which decreased our sales volumes and increased our operating expense. During 2008, we charged $1,709,667 of workover expense to lease operating expense, resulting in decreased cash flow. These decreases in cash provided by operations were partially offset by record high prices for crude oil and natural gas through the first half of 2008. The decrease in cash provided by operations from 2006 to 2007 is primarily from changes in accounts payable decreasing cash by

$1,655,119 due to settlement of outstanding payables in 2007 and a $2,753,788 or 60% increase in general and administrative cost due to the addition of employees in 2007. These decreases in cash provided by operations were partially offset by a $3,658,240 or 88% increase in oil and gas revenues from 2006 to 2007. The oil and gas revenue decrease in 2008 from 2007 was primarily due to a decrease in oil sales volume. The oil and gas revenue increases in 2007 and 2006 were primarily due to drilling activity.

Our investing activities during the three years ended December 31, 2008 related primarily to the addition of oil and gas leases and oil and gas drilling activities. We recorded $11,056,436 in development and exploration costs in 2008, $40,830,743 in 2007 and $29,664,142 in 2006. The remaining investing activity during 2008, 2007 and 2006 consisted primarily of equipment additions and changes in our restricted investments.

Our financing activities during 2008 were comprised mainly of a public offering of 6,820,000 shares of common stock for gross proceeds of approximately $18.8 million. The Company paid approximately $1.3 million in commissions and expenses. Our financing activities during 2007 were comprised mainly of proceeds from the exercise of common stock options. Our financing activities during 2006 included the private placement of 19,514,268 shares of our common stock for gross proceeds of approximately $39,444,438 in March 2006 and the private placement of 12,075,000 shares of our common stock for gross proceeds of approximately $50,111,250 in December 2006.

As we operate the majority of our acreage, specifically the Eastern Bakken acreage, we have the ability to adjust our drilling schedule to reflect the changing commodity price environment. Should we sell off some of our acreage and give up the right to operate, we will become subject to obligations imposed by others, without the ability to control our drilling schedule. Since we have not drawn against our Credit Facility at December 31, 2008, our primary obligations are our office lease and our two drilling rig contracts. During the second quarter of 2008, we entered into two-year contracts for the use of two new-build drilling rigs. The first rig was placed into operation in November 2008 and entails a two-year drilling commitment or specific termination fees if drilling activity is cancelled. Agreement terms require utilization of the rig and payment of day rates or the payment of standby rates if the rig is not utilized. The estimated termination fee for the first rig is approximately $5.3 million as of December 31, 2008. The termination fee on the first rig will continue to decrease as long as the rig remains active. Delivery of the second rig has been placed on hold with the drilling contractor. In the event we do not to take delivery of the rig, the termination fee could be up to $5.6 million and terms are still being negotiated. Subsequent to the end of the fourth quarter 2008, we were able to negotiate with the drilling contractor an approximate 20% reduction in rig day rates for the rig that is currently operating. We cannot offer any assurance that we will be able to negotiate a satisfactory resolution to this issue. Both we and the rig owner are attempting to find another company that will take over our obligations, although there can be no assurance that we will be able to do so.

All of our leases on the FBIR have a minimum of nearly three and a half years remaining; therefore we do not have to drill wells in order to preserve our lease position. We continue to monitor our overhead costs and are attempting to adjust and stay in line with the decline in commodity prices.

In September 2008 we executed a $20 million Credit Facility with Bank of the West, NA. The borrowing base, reflecting the maximum amount that may be outstanding under the Credit Facility at any time, is $3 million as of December 31, 2008. The borrowing base will be re-determined on May 1, 2009 and thereafter semi-annually each May 1 and November 1. If oil and natural gas prices significantly decline for an extended period of time, our lender could reestablish the borrowing base by evaluating our reserves at substantially lower oil and natural gas prices. Such determination could result in a negative revision to our proved reserve value and reduce our borrowing base. Currently the facility is undrawn, and we have no long-term debt.

If we borrow funds, we will be obligated to make periodic interest or other debt service payments and may be subject to additional restrictive covenants. The ability to borrow 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 seek to raise additional capital through the issuance and sale of equity securities, the sales, if successfully completed, may be at prices below the market price of our stock, and our shareholders may suffer significant dilution.

In order to fund our 2009 and later years' capital expenditures, we will complete one or a combination of the following options, whichever option(s) is (are) most favorable:

- Issuance of public equity
- Issuance of public debt
- Capital sharing arrangements with oil and gas industry partners
- Sell-down of interest in existing properties
- Terminate drilling rig contracts and pay a penalty to drilling contractor under the terms of the contract if we are not able to find another company to take over the drilling contractor obligations

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, additional joint ventures or selling interests in our existing acreage. Our ability to succeed in any of these capital-raising activities 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, particularly in light of the current widespread economic downturn.

We had working capital of $15.4 million inclusive of cash and cash equivalents of $7.6 million as of December 31, 2008. Our working capital included $6.5 million of prepaid tubular goods for the first six wells of our 2009 drilling program, which have been reported as prepaid expenses as we have not taken physical delivery of the goods as of December 31, 2008. These costs will be applied to our share of the drilling costs for the first six wells, or will be recovered from our drilling partners. Based on our original 2009 drilling and exploration program, the Company anticipated that our 2009 capital expenditures in the Williston Basin would be approximately $11.3 million. While we cannot fully assess our capital expenditures or the timing of expenditures in the Vermillion Basin as we do not operate the properties, we anticipate that two of the wells that were horizontally drilled during 2008 could be completed during 2009. These costs cannot be determined at this time due to the uncertainty of commodity prices and expenditures. We estimated that our share of the completion costs would not exceed $4.0 million.

Operating Results

Fiscal Year Ended December 31, 2008 Compared to Fiscal Year Ended December 31, 2007

Natural Gas sales revenues. Natural gas sales revenues increased by $318,491 to $1,371,822 for the year ended December 31, 2008, from $1,053,332 for the same period of 2007 $62,804 of the increase was due to a 5% increase in volume and $255,687 of the increase was due to a 24% increase in average price. Natural gas sales volumes were 209,815 Mcf for the year ended December 31, 2008, compared to 200,191 Mcf for the same period in 2007 and the average price we realized on the sale of our natural gas was $6.54 per Mcf in 2008 compared to $5.26 per Mcf in 2007. During the fourth quarter of 2008, natural gas prices in Wyoming declined to a level that we have decided to shut-in our Wyoming operated wells until prices improve.

Oil sales revenues. Oil sales revenues decreased by $1,367,236 to $5,396,781 for the year ended December 31, 2008, from $6,764,017 for 2007. This decrease is attributed to a $3,337,586 negative impact due to a 38% decrease in volume offset and by a $1,970,350 positive impact due to a 29% increase in average price. During the second and third quarter of 2008, three operated oil wells were shut in pending workover and completion activities. This contributed to the decline in our oil sales volumes to 63,595 barrels for 2008 compared to 102,914 barrels for the same period in 2007, whereas the average price we realized on the sale of our oil increased to $84.86 per barrel for the year ended December 31, 2008, from $65.72 for the same period in 2007.

Interest Income. Interest income decreased by $1,306,842 to $196,187 in 2008 from $1,503,029 for the same period in 2007 due to a decrease in average investible cash throughout the year.

Oil and gas production expense. Our oil and gas production expense increased by $1,820,863 to $3,578,580 for the year ended December 31, 2008, from $1,757,717 for the same period in 2007. The increase is primarily due to workover expense of $1,709,667 recorded during the year.

Depletion, depreciation, amortization and abandonment liability accretion ("DDA") expense. Our depletion, depreciation, amortization and abandonment liability accretion expense decreased by $1,034,554 to $4,172,077 for the fiscal year ended December 31, 2008, from $5,206,631 for the same period in 2007. Due to impairment charges taken in 2007 and 2008, the full cost pool was lower resulting in a lower DDA charge for 2008.

Asset impairment. During the last half of 2008, crude oil and natural gas prices dropped from their highs set in the summer of 2008 and the Company's full cost pool exceeded the ceiling by approximately $47.5 million after taking into account decrease in prices following the period ends. Subsequent to the end of the third and fourth quarters of 2008, there was no recovery in price and therefore impairment expenses of $15.5 million and $32.0 million were recorded in the third and fourth quarters of 2008, respectively.

In 2007, we recorded an impairment of $34.0 million primarily as the result of our 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.

General and administrative expense. General and administrative expense increased by $841,086 to $8,175,472 for the fiscal year ended December 31, 2008, from $7,334,386 for the same period in 2007. Included in the general and administrative expense for the fiscal year ended December 31, 2008 is a stock-based compensation charge of $3,551,433 for options issued to officers, directors and employees compared to $2,452,291 for the year ended December 31, 2007. The increase in general and administrative expenses for the fiscal year ended December 31, 2008, also reflects an increase in our level of activity and an increase in the number of employees. As of December 31, 2008, we had 17 full-time employees and two contract consultants as compared to 15 full-time employees and three contract consultants at December 31, 2007. Salary and related expenses decreased by $578,897 to $2,336,276 for the year ended December 31, 2008, from $2,915,173 in 2007. This decrease is due to the reduction in employee bonuses in 2008 versus 2007, partially offset by the addition of two new employees in 2008.

Gain on currency exchange. In 2008, a decrease in the value of the Canadian dollar resulted in a loss of $36,725 on currency exchange as compared to a gain in 2007 of $792,467.

Net loss. Our net loss increased by $18,312,174 to a net loss of $56,498,064 for the year ended December 31, 2008, from a net loss of $38,185,890 for 2007. As more fully described above, the asset impairment of $47,500,000 in 2008 was the primary cause of the increase as compared to an asset impairment charge of $34,000,000 in 2007. In addition, the decrease in oil production revenue, interest income and the increase in oil and gas production expense contributed to the increase in net loss.

Adjusted EBITDA. Our Adjusted EBITDA decreased by $3,918,395 to $(1,237,829) for the year ended December 31, 2008, from $2,680,565 for the same period of 2007. As shown in the following table, this decrease is the primarily the result of decreased revenues and increased production 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,		
	2008	2007	Change
Oil and gas production revenues	$ 6,768,603	$7,817,349	$(1,048,746)
Interest revenue	196,187	1,503,029	(1,306,842)
Total revenue	6,964,790	9,320,378	(2,355,588)
Oil and gas production expense	3,578,580	1,757,717	1,820,863
General and administrative expense excluding stock compensation	4,624,039	4,882,095	(258,056)
Adjusted EBITDA	$(1,237,829)	$2,680,566	$(3,918,395)

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

Natural Gas sales revenues. Natural gas sales revenues increased by $334,405 to $1,053,331 for the year ended December 31, 2007, from $718,926 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 $5.26 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 $3,323,835 to $6,764,017 for the year ended December 31, 2007, from $3,440,182 for 2006. In 2007, we benefited 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 $65.72 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 $696,968 to $1,503,029 in 2007 from $806,061 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 $793,032 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 $35,399,850 to a net loss of $38,185,890 for the year ended December 31, 2007, from a net loss of $2,786,040 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	$3,658,243
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

Financial Instruments and Other Instruments

As at December 31, 2008, 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

During the first nine month of 2008, our industry has experienced a significant increase in the cost of drilling rigs and related oil field services. During most of 2007 and 2008, drilling rigs were difficult to contract and we could not be assured that we could secure third party services. At the close of 2008 and continuing into 2009, due to lower crude oil and natural gas prices, many drilling rigs were idled and the availability of drilling rigs has increased. During 2008, commodity prices were at or near all time levels and we experienced the decline of crude oil and gas from record highs in July 2008 of $140 per barrel for crude oil and $13 per mcf of natural gas to below $40 per barrel of oil and $5 per mcf of gas at year end 2008. Currently, qualified employees are more readily available; however we still must compete for employees within our 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, 2008, information with respect to our known contractual obligations:

	Payments due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual Obligations					
Long-Term Obligations—Office Facilities	$ 979,293	$ 265,408	$ 566,564	$147,321	$—
Drilling Rig Obligations	10,840,475	7,315,625	3,524,850	—	—

During the second quarter of 2008, the Company entered into two-year contracts for the use of two new-build drilling rigs. The first rig was placed into operation in November 2008 and entails a two year drilling commitment or specific termination fees if drilling activity is cancelled. The terms of that agreement require utilization of the rig and payment of day rates or the payment of standby rates if the rig is not utilized. The estimated termination fee for the first rig is approximately $5.3 million as of December 31, 2008. The termination fee on the first rig will continue to decrease as long as we keep the rig active. Our second rig has been placed on hold with the drilling contractor. We are negotiating with the rig contractor to either cancel or delay our obligation with respect to the second rig and avoid all or a part of the contractual $5.6 million cancellation penalty.

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.

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 quarterly 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 quarterly 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 $210,000 in our gross gas production revenue for the fiscal year ended December 31, 2008. A $1.00 per barrel change in the market price of oil would result in a change of approximately $64,000 in our gross oil production revenue for the fiscal year ended December 31, 2008. 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 $77,000 in our interest income for the fiscal year ended December 31, 2008 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, 2008 and 2007, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 10, 2009 expressed an unqualified opinion on the effectiveness of Kodiak Oil & Gas Corp.'s internal control over financial reporting.

/s/ HEIN & ASSOCIATES LLP

Denver, Colorado
March 10, 2009

KODIAK OIL & GAS CORP.
CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,581,265	$ 13,015,318
Accounts receivable		
Trade	1,934,818	1,373,843
Accrued sales revenues	516,870	789,652
Prepaid expenses and other	10,621,980	198,996
Total Current Assets	20,654,933	15,377,809
Oil and gas properties (full cost method), at cost:		
Proved oil and gas properties	97,934,058	77,272,437
Unproved oil and gas properties	11,985,533	21,904,737
Wells in progress	728,093	414,074
Less-accumulated depletion, depreciation, amortization, accretion and asset impairment	(92,804,911)	(41,204,821)
Net oil and gas properties	17,842,773	58,386,427
Other property and equipment, net of accumulated depreciation of $270,620 in 2008 of $176,458 in 2007	272,705	312,017
Restricted investments	246,068	255,068
Total Assets	$ 39,016,479	$ 74,331,321
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 4,125,335	$ 5,163,457
Advances from joint interest owners	1,105,740	—
Total Current Liabilities	5,231,075	5,163,457
Noncurrent Liabilities:		
Asset retirement obligation	787,180	874,498
Total Liabilities	6,018,255	6,037,955
Commitments and Contingencies—Note 7		
Stockholders' Equity:		
Common stock—no par value; unlimited authorized		
Issued and outstanding: 95,129,431 shares in 2008 and 87,992,926 shares in 2007		
Contributed surplus	136,297,845	115,094,923
Accumulated deficit	(103,299,621)	(46,801,557)
Total Stockholders' Equity	32,998,224	68,293,366
Total Liabilities and Stockholders' Equity	$ 39,016,479	$ 74,331,321

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,		
	2008	2007	2006
Revenues:			
Gas production	$ 1,371,822	$ 1,053,331	$ 718,926
Oil production	5,396,781	6,764,017	3,440,182
Interest	196,187	1,503,029	806,061
Total revenue	6,964,790	9,320,377	4,965,169
Cost and expenses:			
Oil and gas production	3,578,580	1,757,717	964,685
Depletion, depreciation, amortization and accretion	4,172,077	5,206,631	2,173,918
Asset impairment	47,500,000	34,000,000	—
General and administrative	8,175,472	7,334,386	4,580,598
(Gain)/loss on currency exchange	36,725	(792,467)	32,008
Total costs and expenses	63,462,854	47,506,267	7,751,209
Net loss	$(56,498,064)	$(38,185,890)	$(2,786,040)
Basic & diluted weighted-average common shares outstanding	90,739,316	87,742,996	71,425,243
Basic & diluted net loss per common share	$ (0.62)	$ (0.44)	$ (0.04)

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.

STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Contributed Surplus	Accumulated Deficit	Total Equity
Balance December 31, 2005:	54,547,158	$ 27,139,298	$ (5,829,627)	$ 21,309,671
Issuance of stocks for cash:				
—pursuant to equity offering	31,589,268	89,555,687		89,555,687
—pursuant to exercise of options	1,412,000	384,372		384,372
Share issuance costs		(6,346,236)		(6,346,236)
Employee stock grants	—	—		—
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 equity offering	—	—		—
—pursuant to exercise of options	363,500	382,150		382,150
Share issuance costs		—		—
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
Issuance of stocks for cash:				
—pursuant to equity offering	6,820,005	18,755,000		18,755,000
—pursuant to exercise of options	312,500	180,000		180,000
Share issuance costs		(1,283,511)		(1,283,511)
Employee stock grants	4,000	154,655		154,655
Stock-based compensation		3,396,778		3,396,778
Net loss			(56,498,064)	(56,498,064)
Balance December 31, 2008:	95,129,431	$136,297,845	$(103,299,621)	$ 32,998,224

SEE ACCOMPANYING NOTES

KODIAK OIL & GAS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2008	2007	2006
Cash flows from operating activities:			
Net loss	$(56,498,064)	$(38,185,890)	$ (2,786,040)
Reconciliation of net loss to net cash (used in) provided by operating activities:			
Depletion, depreciation, amortization and accretion	4,172,077	5,206,631	2,173,918
Asset impairment	47,500,000	34,000,000	—
Asset retirement	—	(29,893)	—
Stock based compensation	3,551,433	2,452,291	1,527,361
Changes in current assets and liabilities:			
Accounts receivable-trade	(560,975)	503,342	(1,429,204)
Accounts receivable-accrued sales revenue	272,782	(122,661)	(440,585)
Prepaid expenses and other	(767,069)	(95,289)	(73,076)
Accounts payable and accrued liabilities	155,297	(1,655,119)	4,168,775
Net cash (used in)/provided by operating activities	(2,174,519)	2,073,412	3,141,149
Cash flows from investing activities:			
Oil and gas properties	(11,209,258)	(47,649,681)	(35,426,830)
Equipment	(54,850)	(229,210)	(52,976)
Prepaid tubular goods	(9,655,915)	—	—
Restricted investment: designated as restricted	—	(30,616)	(82,052)
Restricted investment: undesignated as restricted	9,000	—	10,600
Net cash (used in) investing activities	(20,911,023)	(47,909,507)	(35,551,258)
Cash flows from financing activity:			
Proceeds from the issuance of shares	18,935,000	382,150	89,940,060
Issuance costs	(1,283,511)	—	(6,346,236)
Net cash provided by financing activities	17,651,489	382,150	83,593,824
Net change in cash and cash equivalents	(5,434,053)	(45,453,945)	51,183,715
Cash and cash equivalents at beginning of the period	13,015,318	58,469,263	7,285,548
Cash and cash equivalents at end of the period	$ 7,581,265	$ 13,015,318	$ 58,469,263
Supplemental cash flow information			
Oil & gas property accrual included in Accounts payable and accrued liabilities	$ 1,457,189	$ 1,544,868	$ 4,605,396
Asset retirement obligation	$ (65,143)	$ 526,868	$ 164,503

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 NYSE Alternext US 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 in consolidation. The majority of the Corporation's business is transacted in US dollars and, accordingly, the financial statements are expressed in US dollars.

Use of Estimates in the Preparation of Financial Statements

The preparation of the financial statements in conformity with GAAP 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 at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company evaluates its estimates on an on-going basis and 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. Our most significant financial estimates are associated with our estimated proved oil and gas reserves.

Liquidity and Capital Resources

In order to fund the Company's 2009 and later years' capital expenditures, the Company will complete one or a combination of the following options, whichever option(s) is (are) most favorable:

- Issuance of public equity
- Issuance of public debt
- Capital sharing arrangements with oil and gas industry partners
- Sell-down of interest in existing properties
- Terminate drilling rig contracts and pay a penalty to drilling contractor under the terms of the contract if we are not able to find another company to take over the drilling contractor obligations

The Company's ability to fund its operations in future periods will depend upon its future operating performance, and more broadly, on the availability of equity and debt financing or selling interests in its existing acreage. The Company's ability to succeed in any of these capital-raising activities will be affected by prevailing economic conditions in its industry and financial, business and other factors, some of which are beyond the Company's control. The Company cannot be certain that additional funding will be available on acceptable terms, or at all, particularly in light of the current

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

widespread economic downturn. If we are unable to raise additional capital when required or on acceptable terms, the Company may have to significantly delay, scale back or discontinue its drilling or exploration program, seek to enter into additional joint venture arrangements with third parties, or seek to sell one or more of its properties, on terms or conditions that may not be as favorable as otherwise may be obtained.

Cash and Cash Equivalents

Cash and cash equivalents consist of all highly liquid investments that are readily convertible into cash and have original 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.

As of December 31, 2008, the Company had approximately $7.2 million in a money market account with its bank. The money market account is limited to six withdrawals per month; however, there are no other redemption restrictions. Therefore, the Company classified the entire balance as Cash and Cash Equivalents at December 31, 2008.

Prepaid Expenses and Other

Included in prepaid expenses and other are deposits made on orders of tubular goods required for the Company's drilling program. As of December 31, 2008 there was approximately $9.7 million of deposits made and recorded. The cost basis of the tubular goods is depreciated as a component of oil and gas properties once the inventory is used in drilling operations. The deposit is non-refundable. At December 31, 2008, the market value of the Company's tubular goods inventory approximated the cost basis. As of December 31, 2007, there were no significant deposits made or recorded related to orders of tubular goods.

Restricted Investment

The restricted investments are no longer used as security for our outstanding letters of credit. The investments are short term certificates of deposits, the balance as of December 31, 2008 was classified as a short term investment. The Company's Credit Facility (see note 8) is now used as security for our outstanding letters of credit.

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, 2008, over 84% 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

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

December 31, 2008, 2007 and 2006 purchases by the following companies exceeded 10% of the total oil and gas revenues of the company.

	For the Year Ended December 31,		
	2008	2007	2006
Eighty Eight Oil LLC	84%	80%	76%
ABQ Gas Marketing	4%	12%	0%
Duke Energy Field Services	6%	3%	11%

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 these costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full cost pool.

Depletion of exploration and development costs and depreciation of production equipment is computed using the units-of-production method based upon estimated proved oil and gas reserves as determined by the Company's engineers and audited by independent petroleum engineers. Costs included in the depletion base to be amortized include (a) all proved capitalized costs including capitalized asset retirement costs net of estimated salvage values, less accumulated depletion, (b) estimated future development cost to be incurred in developing proved reserves; and (c) estimated dismantlement and abandonment costs, net of estimated salvage values, that have not been included as capitalized costs because they have not yet been capitalized as asset retirement costs. The costs of unproved properties are withheld from the depletion base until it is determined whether or not proved reserves can be assigned to the properties. The properties are reviewed quarterly for impairment. 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. During 2008 and 2007 approximately $17.2 million and $1.1 million respectively, of unproved land costs were reclassified to proved property and was included in the ceiling test and depletion calculations. There were no reclassifications in 2006.

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

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

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 for a period of 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 a quarterly basis in accordance with applicable rules established by the SEC and may be adjusted based on that data.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed quarterly 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. 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. 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 cost 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 of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower of unproved properties that are subject to amortization. Should capitalized costs exceed 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.

In 2007, primarily as 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, the Company recorded an impairment expense of $34.0 million.

During the last half of 2008, oil and natural gas prices decreased significantly from the record highs seen during the summer of 2008. Natural gas prices in the Rocky Mountains decreased significantly due to the reduction in take-away capacity caused by pipeline maintenance and repairs during the fall of 2008. The Company removed four wells with approximately 348,000 BOE from its proved undeveloped (PUD) category of its reserve base. The removal of these proved undeveloped wells from the reserve base was due to one well that became uneconomic based on 2008 pricing and anticipated capital requirements related to the well and three wells that the Company removed from its

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

drilling plans. After taking into account the decreases in the reserve base due to the above factors and the decreases in prices an impairment expense of $47.5 million was recorded for the year ended 2008.

Wells in Progress

Wells in progress at December 31, 2008 and December 31, 2007, represent the costs associated with wells that have not reached total depth or been completed as of period end. They are classified as wells in progress and withheld from the depletion calculation and the ceiling test. The costs for these wells is then transferred to proved property when the wells reach total depth and are cased and the costs 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. For the year ended December 31, 2007 the Company reclassified approximately $1.1 million of unproved property costs to the full cost pool. The Company recorded an impairment expense of $34.0 million in 2007. For the year ended December 31, 2008, the Company reclassified approximately $17.2 million of unproved property cost to the full cost pool. The Company recorded an impairment expense of $47.5 million in 2008.

Deferred Financing Costs

Deferred financing costs include debt issuance costs incurred in connection with the Company's Credit Agreement, which are being amortized over the two year term of the Credit Facility (see Note 8). The Company recorded amortization expense of $7,330 as of December 31, 2008.

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, 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

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

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, 2008, and December 31, 2007 were not significant.

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 is allocated to operating expense using a systematic and rational method. As of December 31, 2008, and December 31, 2007, the Company has recorded a net asset of $501,900 and $660,986 and a related liability of $787,180 and $874,498, respectively. In December 2007, the Company revised its estimated dismantlement and abandonment costs based upon the actual costs of recently plugged and abandoned wells. The information below reconciles the value of the asset retirement obligation for the periods presented.

	For the Period Ended	
	December 31, 2008	December 31, 2007
Balance beginning of period	$ 874,498	$249,695
Liabilities incurred	—	60,289
Liabilities settled	(147,252)	(3,021)
Revisions in estimated cash flows	—	482,544
Accretion expense	59,934	84,991
Balance end of period	$ 787,180	$874,498

Off Balance Sheet Arrangements

Other than standard operating leases, the Company did not have any off-balance sheet financing arrangements at December 31, 2008 and December 31, 2007.

Recently Adopted Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements." The statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. In February 2008, the FASB issued Staff Position No. FAS 157-2 which proposed a one year deferral for the implementation of SFAS 157 for

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

non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (less frequent than annually).

On January 1, 2008 we elected to implement this statement with the one-year deferral. The adoption of SFAS No. 157 did not have a material impact on our financial position, results of operations or cash flows. Beginning January 1, 2009, we will adopt the provisions for non-financial assets and non-financial liabilities that are not required or permitted to be measured at fair value on a recurring basis. We are in the process of evaluating this standard with respect to our effect on non-financial assets and liabilities and have not yet determined the impact that it will have on our financial statements upon full adoption in 2009.

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 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 adoption of FAS 159 did not have a material impact on the Company's financial position or results of operations.

Recently Issued Accounting Pronouncements

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 March 2008, the FASB issued FAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities" ("FAS 161"). FAS 161 amends and expands the disclosure requirements of FAS 133, "Accounting for Derivative Instruments and Hedging Activities" and requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement is effective for financial statements issued

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

for fiscal periods beginning after November 15, 2008. Earlier adoption is not permitted. We do not believe the adoption of FAS 161 will have a material impact on our consolidated financial statements.

In April 2008, the FASB issued FASB Staff Position ("FSP") FAS 142-3, "Determination of Useful Life of Intangible Assets" ("FSP FAS 142-3"). FSP FAS 142-3 amends the factors that should be considered in developing the renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FAS 142, "Goodwill and Other Intangible Assets." FSP FAS 142-3 also requires expanded disclosure related to the determination of intangible asset useful lives. FSP FAS 142-3 is effective for fiscal years beginning after December 15, 2008. Earlier adoption is not permitted. We do not believe the adoption of FAS FSP 142-3 will have a material impact on our consolidated financial statements.

In May 2008, the FASB issued Statement of Financial Accounting Standards No. 162, *The Hierarchy of Generally Accepted Accounting Principles* ("SFAS 162"). SFAS 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with U.S. generally accepted accounting principles. The Statement becomes effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to the auditing literature. The adoption of SFAS 162 will not have an impact on the Company's financial position, results of operations or cash flows.

In June 2008, the FASB issued FSP No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities," (FSP EITF 03-6-1). FSP EITF 03-6-1 states that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method. FSP EITF 03-6-1 becomes effective for the Company on January 1, 2009. Management has determined that the adoption of FSP EITF 03-6-1 will not have an impact on the Financial Statements.

On December 12, 2007, the Securities and Exchange Commission (SEC) published a Concept Release on possible revisions to the disclosure requirements relating to oil and gas reserves as specified in Rule 4-10 of Regulation S-X and Item 102 of regulation S-K. On December 31, 2008, the SEC adopted a final rule that amends its oil and gas reporting requirements. The revised rules change the way oil and gas companies report their reserves in the financial statements. Definitions were updated to be consistent with Petroleum Resource Management System (PRMS). Other key revisions include a change in pricing used to prepare reserve estimates, the inclusion of non-traditional resources in reserves, the allowance for use of new technologies in determining reserves, optional disclosure of probable and possible reserves and other new disclosures. The revised rules are effective for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10-K and 20-F for fiscal years ending December 31, 2009, and after. The SEC is precluding application of the new rules in quarterly reports prior to the first annual report in which the revised disclosures are required. Early adoption is not permitted. The changes are considered a change in accounting principle that is inseparable from a change in accounting estimate pursuant to *FASB Statement No. 154, Accounting Changes and Error Corrections*, and should be accounted for prospectively. Management is evaluating the impact of the adoption of this final SEC ruling on disclosure requirements relating to our oil and gas reserves and does not anticipate that the implementation of the new reporting requirements will have a material impact on the consolidated results of operations, financial position or liquidity.

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,		
	2008	2007	2006
Property Acquisition costs:			
Proved	$ —	$ —	$ —
Unproved	—	4,285,277	7,225,875
Exploration costs	8,893,293	28,960,843	12,534,859
Development costs	2,163,143	11,869,900	17,129,283
Total	$11,056,436	$45,116,021	$36,890,017
Total excluding asset retirement obligation	$10,909,184	$44,576,209	$36,725,586

Depletion expense related to the proved properties per equivalent BOE of production for the years ended December 31, 2008, 2007, and 2006 were $32.18, $39.30, and $25.63, respectively.

At December 31, 2008 and 2007, the Company's unproved properties consisted of leasehold acquisition costs in the following areas:

	2008	2007
Colorado	$ 124,656	$ 2,166,250
Montana	803,386	2,151,632
North Dakota	10,038,305	4,723,540
Wyoming	1,019,186	12,863,315
	$11,985,533	$21,904,737

The following table sets forth a summary of oil and gas property costs not being amortized as of December 31, 2008 by the year in which such costs were incurred:

	Unproved Additions by Year
Prior	$ 931,794
2006	1,996,860
2007	1,758,439
2008	7,298,440
Total	$ 11,985,533

During 2008 and 2007 approximately $17.2 million and $1.1 million respectively, of unproved land costs was reclassified to proved property and was included in the ceiling test and depletion calculations.

We plan to make capital expenditures of approximately $15.3 million for 2009. Of this $15.3 million in capital expenditures, we have estimated that we will incur $11.3 million in the exploration of the Bakken play in North Dakota. Depending on the timing of the receipt of permits from regulatory agencies and the success of each well, we expect to drill up to nine gross wells in this

Note 3—Oil and Gas Property (Continued)

area in 2009. The unproved costs associated with the Company's drilling projects will be transferred to proved properties as the wells are drilled over the next five to ten years.

Note 4—Wells in Progress

The following table reflects the net changes in capitalized additions to wells in progress during 2008 and 2007, and does not include amounts that were capitalized and reclassified to producing wells in the same period.

	For the Year Ended December 31, 2008	For the Year Ended December 31, 2007
Beginning balance	$ 414,074	$ 7,700,415
Additions to capital wells in progress costs pending the determination of proved reserves	728,093	414,074
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves to full cost pool	(414,074)	(7,700,415)
Ending balance	$ 728,093	$ 414,074

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	
	2008	2007
Wells in progress capitalized for one year or less	$728,093	$414,074
Wells in progress capitalized for one year or more	—	—
Ending balance at December 31	$728,093	$414,074
Number of projects with wells in progress that have been capitalized less than one year	3	2

Note 5—Common Stock

During 2007, the Company issued 363,500 common shares through the exercise of employee options for gross proceeds of $382,150.

On July 14, 2008, the Company filed a Registration Statement on Form S-3 with the United States Securities and Exchange Commission. Under this registration statement, which was declared effective on July 24, 2008, we may from time to time offer and sell common stock and debt securities that may be fully and unconditionally guaranteed by all of our subsidiaries for up to $150 million.

In August 2008, the Company issued 6,820,000 common shares in a public offering for gross proceeds of $18,755,000. The Company paid $1,283,511 in commissions and expenses. The net proceeds

Note 5—Common Stock (Continued)

will be used primarily for drilling and completion activities on the Company's leases in the Bakken oil play located on the Fort Berthold Indian Reservation and for other general corporate activities.

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 2,296,000 stock options and 24,000 shares of restricted stock in 2008. As of December 31, 2008, the Company has outstanding options to purchase 7,507,499 common shares at prices from $0.36 to $6.26.

For the years ended December 31, 2008, 2007 and 2006, the Company recorded stock-based compensation of $3,551,433, $2,452,291, and $1,527,361 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, 2008	December 31, 2007	December 31, 2006
Risk free rates	1.60 - 4.53%	4.46 - 5.89%	4.56 - 5.25%
Dividend yield	0%	0%	0%
Expected volatility	54.37 - 104.22%	53.45 - 56.26%	62.79 - 64.92%
Weighted average expected stock option life	4.98 years	5.86 years	3.36 years
The weighted average fair value at the date of grant for stock options granted is as follows:			
Weighted average fair value per share	$ 1.08	$ 3.33	$ 1.58
Total options granted	2,296,000	2,044,000	2,110,000
Total weighted average fair value of options granted	$ 2,147,541	$ 6,800,579	$ 3,339,312

Note 6—Compensation Plan (Continued)

A summary of the stock options outstanding is as follows:

	Number of Options	Weighted Average Exercise Price
Balance outstanding at December 31, 2006	4,636,500	$1.96
Granted	2,044,000	5.83
Canceled	(205,000)	3.81
Exercised	(363,500)	1.05
Balance outstanding at December 31, 2007	6,112,000	$3.25
Granted	2,296,000	1.96
Canceled	(588,001)	4.40
Exercised	(312,500)	0.58
Balance outstanding at December 31, 2008	7,507,499	$2.87
Options exercisable at December 31, 2008	4,635,999	$2.82

At December 31, 2008, stock options outstanding are as follows:

Exercise Price	Number of Shares	Weighted Average Remaining Contractual Life (Years)
$0.36 - $1.00	1,715,500	4.19
$1.01 - $2.00	875,000	1.79
$2.01 - $3.00	965,000	5.77
$3.01 - $4.00	2,246,999	4.77
$4.01 - $5.00	240,000	2.49
$5.01 - $6.26	1,465,000	8.39
	7,507,499	5.05

The aggregate intrinsic value of both outstanding and vested options as of December 31, 2008, was $0, based on the Company's December 31, 2008 closing common stock price of $0.31. 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 2008 was $2,743,989. As of December 31, 2008, there was $3,543,089 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 24,000 restricted stock awards and canceled 20,000 restricted stock awards in 2008. All awards issued in 2008 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, 2008, there were 48,000 unvested shares with a weighted-average grant date

Note 6—Compensation Plan (Continued)

fair value of $4.21 per share and $136,716 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 $243,791 in 2008, $144,298 in 2007, and $62,738 in 2006. The Company has no other material capital leases and no other operating lease commitments.

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

Years ending in December 31,	
2009	265,408
2010	276,827
2011	289,737
2012	147,321
Total	$979,293

During the second quarter of 2008, the Company entered into two-year contracts for the use of two new-build drilling rigs. The first rig was placed into operation in November 2008 and entails a two year drilling commitment or specific termination fees if drilling activity is cancelled. The terms of that agreement require utilization of the rig and payment of day rates or the payment of standby rates if the rig is not utilized. The estimated termination fee for the first rig is approximately $5.3 million as of December 31, 2008. The termination fee on the first rig will continue to decrease as long as we keep the rig active. Our second rig has been placed on hold with the drilling contractor. We are negotiating with the rig contractor to either cancel or delay our obligation with respect to the second rig and avoid all or a part of the contractual $5.6 million cancellation penalty.

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—Credit Agreement

On September 11, 2008, our wholly-owned subsidiary, Kodiak Oil & Gas (USA) Inc., entered into a two-year, revolving, senior secured credit facility (the "Credit Facility") with Bank of the West, NA. While the agreement has a stated value of $20 million, borrowings are limited to a borrowing base, which was $3 million at December 31, 2008. Borrowings made under the Credit Facility are guaranteed by the Company and secured by mortgages on substantially all of our producing oil and gas properties. The Credit Facility also provides for letters of credit that may be used for general corporate purposes. Our aggregate borrowings and outstanding letters of credit under the Credit Facility may not, at any time, exceed the borrowing base. Interest on borrowings under the Credit Agreement accrues at variable interest rates, at our election, at either:

(i) the prime rate plus a margin of 0.0% to 0.25% based on borrowing base utilization; or

(ii) LIBOR plus a margin of 1.50% to 2.00% based on borrowing base utilization.

Note 8—Credit Agreement (Continued)

In addition, an unused line fee of 0.5%, based on the percentage of borrowing base utilized, will accrue on the unused portion of the commitments under the Credit Facility. The Credit Facility requires us to comply with financial covenants that require us to maintain (1) a Current Ratio (defined as current assets plus unused availability under the Credit Agreement divided by current liabilities excluding any mark-to-market assets or liabilities that may occur due to the Company's hedging activities), determined at the end of each quarter, of not less than 1:1; and (2) a interest coverage ratio of trailing twelve month adjusted EBITDA to interest of not less than 3:1; and (3) a total funded debt to tangible net worth ratio of not more than 2:1. The Credit Facility contains additional representations, warranties, covenants, conditions and defaults customary for transactions of this type, including but not limited to: (i) limitations on liens and incurrence of debt covenants; (ii) limitations on investment covenants and (iii) limitations on reorganizations, recapitalizations, liquidations, dissolutions, mergers and other combination covenants. Any outstanding principal balance of the revolving loan, together with any unpaid fees and expenses relating thereto, will be due and payable no later than September 11, 2010. As of December 31, 2008, the Company was in compliance with its covenants under the Credit Facility.

As of December 31, 2008, we had no outstanding borrowings under the Credit Agreement and we had $227,348 in commercial letters of credit outstanding, which is considered usage for purposes of calculating availability and commitment fees. The available borrowing base under the Credit Facility was reduced from $5.0 million to $3.0 million in November 2008. We capitalized $49,809 in deferred financing costs related to the institution of the Credit Facility, which is amortized on a straight line basis over the term of the Credit Facility. Subsequent to December 31, 2008, we have not borrowed against the Credit Agreement nor issued any additional letters of credit.

Kodiak Oil & Gas (USA) Inc. ("Kodiak USA"), a wholly-owned subsidiary of Kodiak Oil & Gas Corporation (the "Company"), entered into an ISDA Master Agreement (the "Agreement"), dated September 30, 2008, with Bank of the West, under which the Company may enter into hedging transactions designed to protect against changes in interest rates, currency exchange rates, and fluctuations in the price of oil, gas, hydrocarbons or other commodities. Kodiak USA's obligations under the Agreement are secured by a Mortgage, Security Agreement, Assignment, Financing Statement and Fixture Filing dated as of September 11, 2008. The Company is a guarantor of Kodiak USA's obligations under the Agreement and the Agreement is cross-defaulted with Kodiak USA's revolving credit facility with Bank of the West. No hedging transactions have been entered into through March 11, 2009.

Note 9—Benefit Plans

401(k) Plan

In 2008 the Company established a 401(k) plan for the benefit of its employees. Eligible employees may make voluntary contributions not exceeding statutory limitations to the plan. The Company matches 100% of employee contributions up to 3% of the employee's salary and 50% of an additional 2% of employee contributions. Employees are vested 100% for all contributions upon participation. The matching contribution recorded in 2008 was $74,696.

Other Company Benefits

The Company provides a health, dental, vision, life, and disability insurance benefit to all regular full-time employees paid to a maximum of $500 per month per employee.

Note 10—Income Taxes

The Company has available a cumulative net operating loss of approximately $79.1 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:

	2008	2007	2006
Future income tax assets:			
Net tax losses carried forward	$ 27,694,637	$ 13,315,114	$ 3,943,586
Stock-based compensation	2,951,654	1,792,234	956,773
Exploration and development expenses	6,119,821	1,267,766	(1,789,320)
Other	(317,416)	(298,716)	92,262
	36,448,696	16,076,398	3,203,301
Valuation allowance for future income tax assets	$(36,448,696)	$(16,076,398)	$(3,203,301)
Future income tax asset, net	$ —	$ —	$ —

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

	2008	2007	2006
Federal	35.0%	35.0%	35.0%
State	2.1%	2.8%	4.5%
Other	(1.0)%	0.0%	(0.3)%
Valuation Allowance	(36.1)%	(37.8)%	(39.2)%
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

Note 10—Income Taxes (Continued)

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 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 11—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 12—Quarterly Financial Information (Unaudited):

The Company's quarterly financial information for fiscal 2008 and 2007 is as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2008				
Total revenue	$ 1,961,537	$ 2,000,690	$ 1,782,351	$ 1,220,212
Revenue from oil and gas operations	1,878,171	1,963,806	1,743,884	1,182,742
Gross profit (loss)(a)	(202,079)	(105,589)	(332,736)	(341,649)
Net loss	(2,632,036)	(1,898,441)	(17,959,649)	(34,007,938)
Basic and diluted net loss per share	$ (.03)	$ (.02)	$ (0.20)	$ (0.37)
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)

(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 2008 was prepared by Netherland, Sewell & Associates, Inc. ("Netherland"), independent petroleum engineers. The 2007 information was prepared by the Company and audited by Netherland. The information for 2006 was prepared by Netherland 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

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

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 known reservoirs under existing economic and operating conditions. Proved developed 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, 2008, 2007 and 2006 with respect to changes in the Company's proved (i.e. proved developed and undeveloped) reserves:

	Crude Oil (Bbls)	Natural Gas (Mcf)
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
Revisions of previous estimates	(443,563)	(556,350)
Purchase of reserves	—	—
Extensions, discoveries, and other additions	39	19,582
Sale of reserves	(80,467)	(731,539)
Production	(63,595)	(209,835)
December 31, 2008	344,445	1,218,010
Proved Developed Reserves, included above:		
Balance, December 31, 2006	493,300	2,399,400
Balance, December 31, 2007	623,950	2,455,661
Balance, December 31, 2008	344,445	1,218,010

As of December 31, 2008, we had estimated proved reserves of 1.2 billion cubic feet ("BCF") of natural gas and 344 thousand barrels ("MBbls") of oil with a present value discounted at 10% of $5.3 million. Our reserves are 100% proved developed and are comprised of 37% natural gas and 63%

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

crude oil on an energy equivalent basis. Our December 31, 2008 natural gas reserves reflect a downward revision of the December 31, 2007 reserves of 5 BCF. Such downward revision of our reserves is primarily associated with our decision to remove our proved undeveloped reserves (PUD) and the decline in crude oil and natural gas prices used to determine year end reserves from 2007 to 2008.

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 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 2008 oil and gas reserves are based on the December 31, 2008 natural gas price of $4.49 per MMBtu (Questar Rocky Mountains price) or $5.88 per MMBtu (Northern Ventura price) and crude oil price of $41.00 per barrel (West Texas Intermediate price). The values for the 2007 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). All prices are adjusted for transportation, quality and basis differentials.

As of December 31, 2008, based on our net oil and gas prices of $24.09 per barrel of crude oil and $3.76 per Mcf of natural gas, the value of Kodiak's proved reserves as calculated under SEC guidelines did not support the costs included in the full cost pool. Due to lower commodity prices and timing of projected drilling, the Company removed all previously recorded proved undeveloped locations (PUD) in 2008. Our December 31, 2008, reserves reflect a downward revision of the December 31, 2007, reserves of 833.8 BOE, primarily related to a change in commodity prices, and removal of our previously recorded proved undeveloped locations (PUD). In determining the net change in prices and production costs for 2008, we classified the removal of our proved undeveloped reserves (PUD) as a quantity revision.

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

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,		
	2008	2007	2006
Future oil and gas sales	$12,881,600	$ 95,071,835	$37,634,700
Future production costs	(5,449,600)	(22,127,559)	(8,920,900)
Future development costs	(218,800)	(10,669,553)	(2,492,500)
Future net cash flows	7,213,200	62,274,723	26,221,300
10% annual discount	(1,885,100)	(26,080,552)	(6,631,500)
Standardized measure of discounted future net cash flows	$ 5,328,100	$ 36,194,171	$19,589,800

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

	Year ended December 31,		
	2008	2007	2006
Balance at beginning of period	$ 36,194,171	$19,589,800	$14,202,806
Sales of oil and gas, net	(3,190,023)	(6,059,632)	(3,194,424)
Net change in prices and production costs	(27,083,680)	10,126,811	(4,965,063)
Net change in future development costs	5,666,286	(8,068,070)	630,351
Extensions and discoveries	289,066	15,524,174	11,720,816
Sale of reserves	(2,029,543)	—	—
Revisions of previous quantity estimates	(12,231,173)	(5,356,105)	(7,798,876)
Previously estimated development costs incurred	3,094,691	8,742,935	2,187,500
Net change in income taxes	—	—	3,954,218
Accretion of discount	4,546,617	1,537,322	2,107,952
Other	71,688	156,936	744,520
Balance at end of period	$ 5,328,100	$36,194,171	$19,589,800

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 Exchange 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 authorizations of management and directors of the issuer; 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 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 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, 2008 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, 2008. 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, 2008 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, 2008, 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, 2008, 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, 2008 and 2007, 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, 2008, and our report dated March 10, 2009 expressed an unqualified opinion.

/s/ HEIN & ASSOCIATES LLP

Denver, Colorado
March 10, 2009

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 2009 Annual Meeting of Shareholders, to be filed within 120 days of December 31, 2008, pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the "2009 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 2009 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 2009 Proxy Statement is incorporated herein by reference.

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

The information responsive to Items 404 and 407 of Regulation S-K to be included in our 2009 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 2009 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.

Kodiak Oil & Gas Corp. 2007 Stock Incentive Plan identified in the exhibit list below.

Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and Lynn A. Peterson identified in the exhibit list below.

Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and Lynn A. Peterson (subsequently amended) identified in the exhibit list below.

Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and James E. Catlin identified in the exhibit list below.

Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and James E. Catlin (subsequently amended) identified in the exhibit list below.

Employment Agreement effective December 1, 2008 between Kodiak Oil & Gas Corp. and Keith Doss identified in the exhibit list below.

Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and James P. Henderson 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(2)	Amended and Restated By-Law No. 1 of the Company
4.1(1)	Kodiak Oil & Gas Corp. Incentive Stock Option Plan
4.2(3)	Kodiak Oil & Gas Corp. 2007 Stock Incentive Plan

Exhibit Number	Description
4.3(4)	Form of Incentive Stock Option Agreement for 2007 Stock Incentive Plan
4.4(4)	Form of Employee Non-incentive Stock Option Agreement for 2007 Stock Incentive Plan
4.5(4)	Form of Directors' Non-incentive Stock Option Agreement for 2007 Stock Incentive Plan
4.6(4)	Form of Restricted Stock Award Agreement for 2007 Stock Incentive Plan
4.7(5)	Form of Non-Incentive Performance-Based Stock Option Agreement
10.1(6)	Fourth Amendment to Lease, dated February 14, 2007, between Transwestern Broadreach WTC, LLC and Kodiak Oil & Gas (USA) Inc.
10.2(7)	Fifth Amendment to Lease, dated May 31, 2007 between Transwestern Broadreach WTC, LLC and Kodiak Oil & Gas (USA) Inc.
10.3(8)	Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and Lynn A. Peterson
10.4(9)	Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and Lynn A. Peterson (subsequently amended by Exhibit 10.3)
10.5(8)	Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and James E. Catlin
10.6(9)	Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and James E. Catlin (subsequently amended by Exhibit 10.5)
10.7(8)	Employment Agreement effective December 1, 2008 between Kodiak Oil & Gas Corp. and Keith Doss
10.8(9)	Executive Employment Agreement effective January 1, 2008 between Kodiak Oil & Gas Corp. and James P. Henderson
10.9(10)	Credit Agreement between Kodiak Oil & Gas (USA) Inc. and Bank of the West, dated as of September 11, 2008
10.10(10)	ISDA Master Agreement between Kodiak Oil & Gas (USA) Inc. and Bank of the West, dated as of September 30, 2008
14.1(11)	Code of Business Conduct and Ethics
21.1(12)	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 Financial 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 Financial 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 Quarterly Report on Form 10-Q (SEC File No. 001-32920), filed on May 8, 2008.

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

(4) 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.

(5) Incorporated by reference to the Registrant's Current Report on Form 8-K (SEC File No. 001-32920), filed on March 19, 2008.

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

(7) Incorporated by reference to the Registrant's Annual Report on Form 10-K (SEC File No. 001-32920), filed on March 14, 2008.

(8) Incorporated by reference to the Registrant's Current Report on Form 8-K (SEC File No. 001-32920), filed on December 30, 2008.

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

(10) Incorporated by reference to the Registrant's Quarterly Report on Form 10-Q (SEC File No. 001-32920), filed on November 6, 2008.

(11) 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.

(12) 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, CH_4, 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)

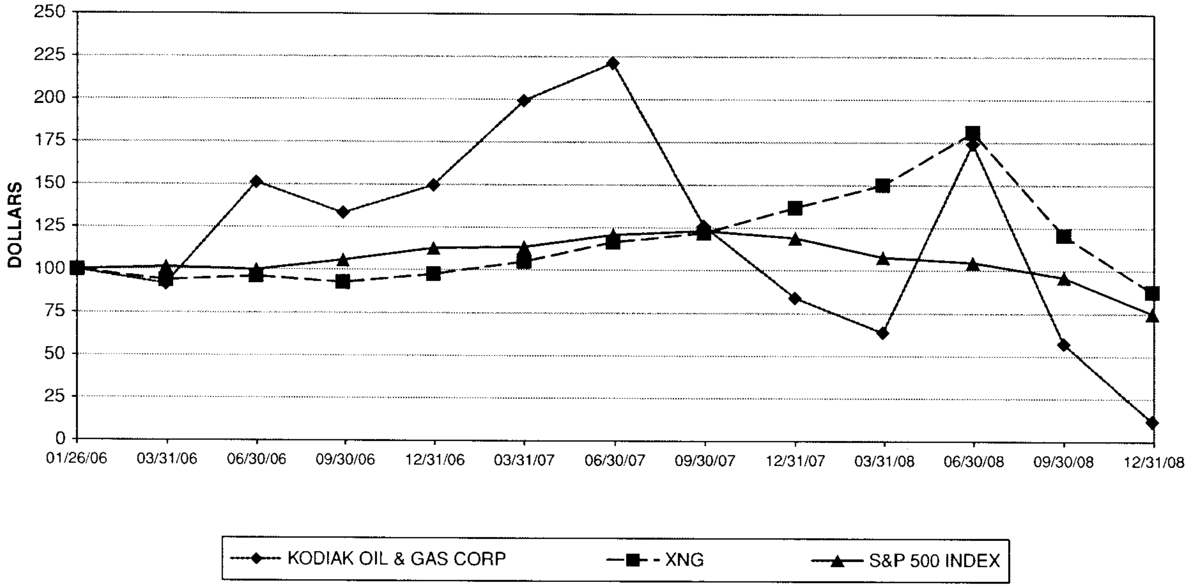
Date: March 11, 2009

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 11, 2009
By: /s/ JAMES E. CATLIN James E. Catlin	Vice President and Chief Operations Officer	March 11, 2009
By: /s/ KEITH DOSS Keith Doss	Chief Financial Officer, Treasurer and Secretary (principal financial officer and principal accounting officer)	March 11, 2009
By: /s/ HERRICK K. LIDSTONE, JR. Herrick K. Lidstone, Jr.	Director	March 11, 2009
By: /s/ RODNEY D. KNUTSON Rodney D. Knutson	Director	March 11, 2009
By: /s/ DON MCDONALD Don McDonald	Director	March 11, 2009

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



COMPANY/INDEX/MARKET	FISCAL YEAR ENDING						
	1/26/2006	3/31/2006	6/30/2006	9/29/2006	12/29/2006	3/30/2007	6/29/2007
Kodiak Oil & Gas Corp.	100.00	91.60	151.15	133.21	149.69	199.24	221.37
XNG	100.00	93.88	96.21	92.64	97.61	105.04	116.45
S&P Composite	100.00	101.52	100.06	105.73	112.81	113.53	120.66

	FISCAL YEAR ENDING					
	9/28/2007	12/31/2007	3/31/2008	6/30/2008	9/30/2008	12/31/2008
Kodiak Oil & Gas Corp.	125.95	83.97	63.74	174.05	57.25	11.83
XNG	121.85	136.73	150.01	180.78	120.63	87.62
S&P Composite	123.11	119.01	107.77	104.83	96.05	74.98

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 K. Doss
Chief Financial Officer, Secretary and Treasurer

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

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

CORPORTE INFORMATION

Stock Exchange Listing
NYSE AMEX: "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 wwwkodiakog.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 World Trade Center
1625 Broadway
Denver, Colorado 80202
Suite: 820
Date: August 13, 2009
Time: 9:00 AM Mountain Daylight Time