WHITING PETROLEUM CORP
Form 10-K
February 25, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2008
or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______________ to _______________

Commission file number: 001-31899
Whiting Petroleum Corporation
(Exact name of registrant as specified in its charter)

Delaware	20-0098515
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 Broadway, Suite 2300 Denver, Colorado	80290-2300
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: (303) 837-1661

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

Common Stock, $0.001 par value	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange
(Title of Class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None.

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

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

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 T 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 registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. T

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. (Check one):

Large accelerated filer T Accelerated filer £ Non-accelerated filer £ 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 T

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2008: $4,499,939,059.

Number of shares of the registrant's common stock outstanding at February 16, 2009: 50,771,882 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2009 Annual Meeting of Stockholders are incorporated by reference into Part III.

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CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms “we,” “us,” “our” or “ours” when used in this Annual Report on Form 10-K refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this Annual Report on Form 10-K:

“3-D seismic” Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

“Bbl” One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil and other liquid hydrocarbons.

“Bbl/d” One Bbl per day.

“Bcf” One billion cubic feet of natural gas.

“Bcfe” One billion cubic feet of natural gas equivalent.

“BOE” One stock tank barrel equivalent of oil, calculated by converting natural gas volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

“CO2 flood” A tertiary recovery method in which CO2 is injected into a reservoir to enhance hydrocarbon recovery.

“completion” The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“farmout” An assignment of an interest in a drilling location and related acreage conditioned upon the drilling of a well on that location.

"FASB" Financial Accounting Standards Board.

“flush production” The high rate of flow from a well during initial production immediately after it is brought on-line.

“GAAP” Generally accepted accounting principles in the United States of America.

“MBbl” One thousand barrels of oil or other liquid hydrocarbons.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet of natural gas.

“Mcfe” One thousand cubic feet of natural gas equivalent.

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units.

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“MMcf” One million cubic feet of natural gas.

“MMcf/d” One MMcf per day.

“MMcfe” One million cubic feet of natural gas equivalent.

“MMcfe/d” One MMcfe per day.

“PDNP” Proved developed nonproducing.

“PDP” Proved developed producing.

“plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

“PUD” Proved undeveloped.

“pre-tax PV10%” The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the Securities and Exchange Commission (“SEC”), net of estimated lease operating expense, production taxes and future development costs, using price and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or Federal income taxes and discounted using an annual discount rate of 10%. Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC. See footnote (1) to the Proved Reserves table in Item 1. “Business” for more information.

“reservoir” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“resource play” Refers to drilling programs targeted at regionally distributed oil or natural gas accumulations. Successful exploitation of these reservoirs is dependent upon new technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.

“working interest” The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

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PART I

Item 1. Business

Overview

We are an independent oil and gas company engaged in acquisition, development, exploitation, production and exploration activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States. We were incorporated in 2003 in connection with our initial public offering.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through property acquisitions, development and exploration activities. As of December 31, 2008, our estimated proved reserves totaled 239.1 MMBOE, representing a 5% decrease in our proved reserves since December 31, 2007. Our 2008 average daily production was 47.9 MBOE/d and implies an average reserve life of approximately 13.6 years.

The following table summarizes our estimated proved reserves by core area, the corresponding pre-tax PV10% value and our standardized measure of discounted future net cash flows as of December 31, 2008, and our December 2008 average daily production:

Core Area	Proved Reserves(1) Oil(2) (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil(2)	Pre-Tax PV10% Value(3) (In millions)	December 2008 Average Daily Production (MBOE/d)
Permian Basin	88.1	57.8	97.7	90%	$ 455.2	11.7
Rocky Mountains	49.2	203.9	83.2	59%	548.2	27.7
Mid-Continent	37.2	11.7	39.1	95%	416.2	7.2
Gulf Coast	3.1	41.6	10.1	31%	105.2	5.0
Michigan	2.4	39.7	9.0	27%	78.2	3.5
Total	180.0	354.8	239.1	75%	$ 1,603.0	55.1
Discounted Future Income Taxes	-	-	-	-	(226.6)	-
Standardized Measure of Discounted Future Net Cash Flows	-	-	-	-	$ 1,376.4	-

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from oil and gas prices as of December 31, 2008 pursuant to current SEC and FASB guidelines.

(2) Oil includes natural gas liquids.

(3) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash

flows but without deducting future income taxes. We believe pre-tax PV10% is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV10% and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

While historically we have grown through acquisitions, we are increasingly focused on a balance between exploration and development programs and continuing to selectively pursue acquisitions that complement our existing core properties. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities.

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Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows;
- seeking property acquisitions that complement our core areas; and
- allocating a portion of our capital budget to leasing and exploring prospect areas.

During 2008, we incurred $1,386.1 million in acquisition, development and exploration activities, including $947.4 million for the drilling of 308 gross (125.7 net) wells. Of these new wells, 115.2 (net) resulted in productive completions and 10.5 (net) were unsuccessful, yielding a 92% success rate. Our current 2009 capital budget for exploration and development expenditures is $474.0 million, which we expect to fund with net cash provided by our operating activities and a portion of the proceeds from the common stock offering we completed in February 2009. Our 2009 capital budget of $474.0 million, however, represents a substantial decrease from the $947.4 million incurred on exploration and development expenditures during 2008. This reduced capital budget is in response to the significantly lower oil and natural gas prices experienced during the fourth quarter of 2008 and continuing into 2009.

Acquisitions and Divestitures

The following is a summary of our acquisitions and divestitures during the last two years. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for more information on these acquisitions and divestitures.

2008 Acquisitions. On May 30, 2008, we acquired interests in 31 producing gas wells, development acreage and gas gathering and processing facilities on approximately 22,000 gross (11,500 net) acres in the Flat Rock field in Uintah County, Utah for an aggregate acquisition price of $365.0 million. After allocating $79.5 million of the purchase price to unproved properties, the resulting acquisition cost is $2.48 per Mcfe. Of the estimated 115.2 Bcfe of proved reserves acquired as of the January 1, 2008 acquisition effective date, 98% are natural gas and 22% are proved developed producing. The average daily net production from the properties was 17.8 MMcfe/d as of the acquisition effective date. We funded the acquisition with borrowings under our credit agreement.

2008 Divestitures. On April 30, 2008, we completed an initial public offering of units of beneficial interest in Whiting USA Trust I (the “Trust”), selling 11,677,500 Trust units at $20.00 per Trust unit, providing net proceeds of $214.9 million after underwriters’ discounts and commissions and offering expenses. Our net profits from the Trust’s underlying oil and gas properties received between the effective date and the closing date of the Trust unit sale were paid to the Trust and thereby further reduced net proceeds to $193.7 million. We used the net offering proceeds to reduce a portion of the debt outstanding under our credit agreement. The net proceeds from the sale of Trust units to the public resulted in a deferred gain on sale of $100.0 million. Immediately prior to the closing of the offering, we conveyed a term net profits interest in certain of our oil and gas properties to the Trust in exchange for 13,863,889 Trust units. We have retained 15.8%, or 2,186,389 Trust units, of the total Trust units issued and outstanding.

The net profits interest entitles the Trust to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate at the time when 9.11 MMBOE have been produced and sold from the underlying properties. This is the equivalent of 8.2 MMBOE in respect of the Trust’s right to receive 90% of the net proceeds from such production pursuant to the net profits interest, and these reserve quantities are projected to be produced by December 31, 2021, based on the reserve report for the underlying properties as of December 31, 2008. The conveyance of the net profits interest to the Trust consisted entirely of proved developed producing reserves of 8.2 MMBOE, as of the January 1, 2008 effective date, representing 3.3% of our proved reserves as of December 31, 2007, and 10.0%, or 4.2 MBOE/d, of our March 2008 average daily net production. After netting our ownership of 2,186,389 Trust units, third-party public Trust unit holders receive 6.9 MMBOE of proved producing reserves, or 2.75% of our total year-end 2007 proved reserves, and 7.4%, or 3.1 MBOE/d, of our March 2008 average daily net production.

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2007 Acquisitions. We did not make any significant acquisitions during the year ended December 31, 2007.

2007 Divestitures. On July 17, 2007, we sold our approximate 50% non-operated working interest in several gas fields located in the LaSalle and Webb Counties of Texas for total cash proceeds of $40.1 million, resulting in a pre-tax gain on sale of $29.7 million. The divested properties had estimated proved reserves of 2.3 MMBOE as of December 31, 2006, and when adjusted to the July 1, 2007 divestiture effective date, the divested property reserves yielded a sale price of $17.77 per BOE. The June 2007 average daily net production from these fields was 0.8 MBOE/d.

During 2007, we sold our interests in several additional non-core oil and gas producing properties for an aggregate amount of $12.5 million in cash for total estimated proved reserves of 0.6 MMBOE as of the divestitures' effective dates. No gain or loss was recognized on the sales. The divested properties are located in Colorado, Louisiana, Michigan, Montana, New Mexico, North Dakota, Oklahoma, Texas and Wyoming. The average daily net production from the divested property interests was 0.3 MBOE/d as of the dates of disposition.

Business Strategy

Our goal is to generate meaningful growth in both production and free cash flow by investing in oil and gas projects with attractive rates of return on capital employed. To date, we have achieved this goal through both the acquisition of reserves and continued field development in our core areas. Because of the extensive property base we have built, we are pursuing several economically attractive oil and gas opportunities to exploit and develop properties as well as explore our acreage positions for additional production growth and proved reserves. Specifically, we have focused, and plan to continue to focus, on the following:

Pursuing High-Return Organic Reserve Additions. The development of large resource plays such as our Williston Basin and Piceance Basin projects has become one of our central objectives. We have assembled approximately 125,600 gross (83,600 net) acres on the eastern side of the Williston Basin in North Dakota in an active oil development play at our Sanish field area, where the Middle Bakken reservoir is oil productive. We have drilled and completed 49 successful Bakken wells (27 operated) in our Sanish field acreage that had a combined net production rate of 7.5 MBOE/d during December 2008. With the acquisition of Equity Oil Company in 2004, we acquired mineral interests and federal oil and gas leases in the Piceance Basin of Colorado, where we have found the Iles and Williams Fork (Mesaverde) reservoirs to be gas productive at our Sulphur Creek field area and the Mesaverde formation to be gas productive at our Jimmy Gulch prospect area. Our initial drilling results in both projects have been positive. In the Piceance acreage, we have drilled and completed 23 successful wells that had a combined net production rate of 9.5 Bcf/d of natural gas during December 2008. In addition to development of our core areas, we have identified opportunities in the Lewis & Clark prospect in the Williston Basin, the Sulphur Creek field – Jimmy Gulch and Wasatch prospects in the Piceance Basin and the Hatfield prospect in the Green River Basin.

Developing and Exploiting Existing Properties. Our existing property base and our acquisitions over the past five years have provided us with numerous low-risk opportunities for exploitation and development drilling. As of December 31, 2008, we have identified a drilling inventory of over 1,400 gross wells that we believe will add substantial production over the next five years. Our drilling inventory consists of the development of our proved and non-proved reserves on which we have spent significant time evaluating the costs and expected results. Additionally, we have several opportunities to apply and expand enhanced recovery techniques that we expect will increase proved reserves and extend the productive lives of our mature fields. In 2005, we acquired two large oil fields, the Postle field, located in the Oklahoma Panhandle, and the North Ward Estes field, located in the Permian Basin of West Texas. We have experienced and anticipate further significant production increases in these fields over the next four to seven years through the use of secondary and tertiary recovery techniques. In these fields, we are actively injecting water and CO_2 and executing extensive re-development, drilling and completion operations, as well as enhanced gas handling and treating capability.

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Growing Through Accretive Acquisitions. From 2004 to 2008, we completed 13 separate acquisitions of producing properties for estimated proved reserves of 226.9 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, land, engineering and geoscience professionals has developed and refined an acquisition program designed to increase reserves and complement our existing properties, including identifying and evaluating acquisition opportunities, negotiating and closing purchases and managing acquired properties. We intend to selectively pursue the acquisition of properties complementary to our core operating areas.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity price volatility. We have historically funded our acquisitions and growth activity through a combination of equity and debt issuances, bank borrowings and internally generated cash flow, as appropriate, to maintain our strong financial position. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt under our credit agreement. To support cash flow generation on our existing properties and help ensure expected cash flows from acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars to provide an attractive base commodity price level, while maintaining the ability to benefit from improvements in commodity prices.

Competitive Strengths

We believe that our key competitive strengths lie in our balanced asset portfolio, our experienced management and technical team and our commitment to effective application of new technologies.

Balanced, Long-Lived Asset Base. As of December 31, 2008, we had interests in 8,871 gross (3,337 net) productive wells across approximately 992,400 gross (514,900 net) developed acres in our five core geographical areas. We believe this geographic mix of properties and organic drilling opportunities, combined with our continuing business strategy of acquiring and exploiting properties in these areas, presents us with multiple opportunities in executing our strategy because we are not dependent on any particular producing regions or geological formations. Our proved reserve life is approximately 13.6 years based on year-end 2008 proved reserves and 2008 production.

Experienced Management Team. Our management team averages 25 years of experience in the oil and gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, each of our acquisition professionals has at least 28 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated detailed geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Our technical team has access to approximately 5,934 square miles of 3-D seismic data, digital well logs and other subsurface information. This data is analyzed with advanced geophysical and geological computer resources dedicated to the accurate and efficient characterization of the subsurface oil and gas reservoirs that comprise our asset base. In addition, our information systems enable us to update our production databases through daily uploads from hand held computers in the field. With the acquisition of the Postle and North Ward Estes properties, we have assembled a team of 14 professionals averaging over 20 years of expertise managing CO_2 floods. This provides us with the ability to pursue other CO_2 flood targets and employ this technology to add reserves to our portfolio. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

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Proved Reserves

Our estimated proved reserves as of December 31, 2008 are summarized in the table below.

	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Future Capital Expenditures (In millions)
Permian Basin:					
PDP	26.8	31.1	31.9	33%	
PDNP	21.8	3.8	22.4	23%	
PUD	39.5	23.0	43.4	44%	
Total Proved	88.1	57.8	97.7	100%	$ 494.0
Rocky Mountains:					
PDP	36.2	113.1	55.0	66%	
PDNP	0.9	6.4	2.0	2%	
PUD	12.1	84.4	26.2	32%	
Total Proved	49.2	203.9	83.2	100%	$ 287.7
Mid-Continent:					
PDP	22.7	8.6	24.2	62%	
PDNP	8.4	1.8	8.6	22%	
PUD	6.1	1.3	6.3	16%	
Total Proved	37.2	11.7	39.1	100%	$ 149.0
Gulf Coast:					
PDP	1.9	25.7	6.2	61%	
PDNP	0.2	3.6	0.8	8%	
PUD	1.0	12.3	3.1	31%	
Total Proved	3.1	41.6	10.1	100%	$ 48.0
Michigan:					
PDP	1.1	30.0	6.1	68%	
PDNP	1.0	5.1	1.9	21%	
PUD	0.3	4.6	1.0	11%	
Total Proved	2.4	39.7	9.0	100%	$ 3.5
Total Company:					
PDP	88.7	208.5	123.4	52%	
PDNP	32.3	20.7	35.7	15%	
PUD	59.0	125.6	80.0	33%	
Total Proved	180.0	354.8	239.1	100%	$ 982.2

Marketing and Major Customers

We principally sell our oil and gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. During

2008, sales to Plains Marketing LP and Valero Energy Corporation accounted for 15% and 14%, respectively, of our total oil and natural gas sales. During 2007, sales to Valero Energy Corporation and Plains Marketing LP accounted for 14% and 13%, respectively, of our total oil and natural gas sales. During 2006, sales to Plains Marketing LP and Valero Energy Corporation accounted for 16% and 12%, respectively, of our total oil and natural gas sales.

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Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit agreement is also secured by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties in the operation of our business.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry.

Regulation

Regulation of Transportation, Sale and Gathering of Natural Gas

The Federal Energy Regulatory Commission (“FERC”) regulates the transportation, and to a lesser extent sale for resale, of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 and regulations issued under those Acts. In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business.

Our natural gas sales are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation and underground storage are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the FERC's jurisdiction, most notably interstate natural gas transmission companies and certain underground storage facilities. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis.

FERC implements The Outer Continental Shelf Lands Act as to transportation and pipeline issues, which requires that all pipelines operating on or across the outer continental shelf provide open access and non-discriminatory transportation service. One of the FERC’s principal goals in carrying out this Act’s mandate is to increase transparency in the market to provide producers and shippers on the outer continental shelf with greater assurance of open access services on pipelines located on the outer continental shelf and non-discriminatory rates and conditions of service on such pipelines.

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We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. In addition, many aspects of these regulatory developments have not become final, but are still pending judicial and final FERC decisions. Regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum product pipelines. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any of the states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors.

Pipeline safety is regulated at both state and federal levels. After a final rule was implemented by the U.S. Department of Transportation on March 15, 2006 that defines and puts new safety requirements on gas gathering pipelines, we have completed an initial screening of gas gathering lines and are implementing programs to comply with applicable requirements of this section.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for crude oil transportation rates that allowed for an increase or decrease in the cost of transporting oil to the purchaser. FERC's regulations include a methodology for oil pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The mandatory five year review has revised the methodology for this index to now be based on Producer Price Index for Finished Goods (PPI-FG), plus a 1.3% adjustment, for the period July 1, 2006 through July 2011. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

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Regulation of Production

The production of oil and gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum allowable rates of production from oil and gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production or sale of oil, gas and natural gas liquids within its jurisdiction.

Some of our offshore operations are conducted on federal leases that are administered by Minerals Management Service, or MMS, and are required to comply with the regulations and orders issued by MMS under the Outer Continental Shelf Lands Act. Among other things, we are required to obtain prior MMS approval for any exploration plans we pursue and our development and production plans for these leases. MMS regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under limited circumstances, MMS could require us to suspend or terminate our operations on a federal lease.

MMS also establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by MMS and the state regulatory authorities is generally applicable to all federal and state oil and gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Regulations

General. Our oil and gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA") issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or that may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or facility construction commences, restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities, limit or prohibit project siting, construction, or drilling activities on certain lands laying within wilderness, wetlands, ecologically sensitive and other protected areas, require remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits, and impose substantial liabilities for pollution resulting from our operations. The EPA and analogous state agencies may delay or refuse the issuance of required permits or otherwise include onerous or limiting permit conditions that may have a significant adverse impact on our ability to conduct operations. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and have not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this trend will continue in the future.

The environmental laws and regulations which have the most significant impact on the oil and gas exploration and production industry are as follows:

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Superfund. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as "CERCLA" or "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of a disposal site or sites where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our ordinary operations, we may generate material that may fall within CERCLA's definition of a "hazardous substance". Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these materials have been disposed or released.

We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other materials may have been disposed or released on, under, or from the properties owned or leased by us or on, under, or from other locations where these hydrocarbons and materials have been taken for disposal. In addition, many of these owned and leased properties have been operated by third parties whose management and disposal of hydrocarbons and materials were not under our control. Similarly, the disposal facilities where discarded materials are sent are also often operated by third parties whose waste treatment and disposal practices may not be adequate. While we only use what we consider to be reputable disposal facilities, we might not know of a potential problem if the disposal occurred before we acquired the property or business, and if the problem itself is not discovered until years later. Our properties, adjacent affected properties, the disposal sites, and the material itself may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed materials, including materials disposed or released by prior owners or operators or other third parties;
- to clean up contaminated property, including contaminated groundwater; or
- to perform remedial operations to prevent future contamination, including the plugging and abandonment of wells drilled and left inactive by prior owners and operators.

At this time, we do not believe that we are a potentially responsible party with respect to any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act. The Oil Pollution Act of 1990, also known as "OPA," and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA establishes a liability limit for onshore facilities of $350.0 million, while the liability limit for offshore facilities is the payment of all removal costs plus up to $75.0 million in other damages, but these limits may not apply if a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or if a party fails to report a spill or to cooperate fully in a cleanup. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of financial responsibility required under OPA may be increased up to $150.0 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative, civil or criminal enforcement actions. We believe we are in compliance with all applicable OPA financial responsibility obligations. Moreover, we are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

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Resource Conservation Recovery Act. The Resource Conservation and Recovery Act, also known as "RCRA," is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements on a person who is either a "generator" or "transporter" of hazardous waste or on an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. RCRA and many state counterparts specifically exclude from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" and thus we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. However, these wastes may be regulated by EPA or state agencies as solid waste. In addition, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated as hazardous waste. Although we do not believe the current costs of managing our materials constituting wastes as they are presently classified to be significant, any repeal or modification of the oil and gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Clean Water Act. The Federal Water Pollution Control Act of 1972, or the Clean Water Act (the "CWA"), imposes restrictions and controls on the discharge of produced waters and other pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit.

Historically, the EPA had regulations under the authority of the CWA that required certain oil and gas exploration and production projects to obtain permits for construction projects with storm water discharges. However, the Energy Policy Act of 2005 nullified most of the EPA regulations that required permitting of oil and gas construction projects. There are still some states that regulate the discharge of storm water from oil and gas construction projects. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. In Section 40 CFR 112 of the regulations, the EPA promulgated the Spill Prevention, Control, and Countermeasure, or SPCC, regulations, which require certain oil containing facilities to prepare plans and meet construction and operating standards. The SPCC regulations were revised in 2002 and will require the amendment of SPCC plans and the modification of spill control devices at many facilities. On May 16, 2007 the EPA extended the compliance dates until July 1, 2009 for both completion and implementation of the plan. The extension will allow time for the EPA to complete additional rule amendments and guidance documents. On December 5, 2008, the EPA published the final amendment to the 2002 SPCC rule to provide increased clarity, to tailor requirements to particular industry sectors, and to streamline certain requirements for a facility owner or operator subject to the rule. The EPA, in accordance with the January 20, 2009 White House memorandum, is delaying by 60 days the effective date of this final rule. The amendments will now become effective on April 4, 2009. We believe that our operations comply in all material respects with the requirements of the CWA and state statutes enacted to control water pollution and that any amendment and subsequent implementation of our SPCC plans will be performed in a timely manner and not have a significant impact on our operations.

Clean Air Act. The Clean Air Act 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 obtain additional permits and incur capital costs in order to remain in compliance. More stringent regulations governing emissions of toxic air pollutants are being developed by the EPA and may increase the costs of compliance for some facilities. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold or have applied for all permits necessary to our operations.

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Global Warming and Climate Control. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases", including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider legislation to regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emission of these gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in Massachusetts, et al. v. EPA, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in Massachusetts that greenhouse gases fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. More recently, in July 2008, EPA released an "Advance Notice of Proposed Rulemaking," regarding possible future regulation of greenhouse gases under the Clean Air Act. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we operate could adversely affect our operations by increasing costs. The cost increases would result from the potential new requirements to install additional emission control equipment and by increasing our monitoring and record-keeping burden.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act, the National Environmental Policy Act, and the Coastal Zone Management Act require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. The Outer Continental Shelf Lands Act, for instance, requires the U.S. Department of Interior to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, the National Environmental Policy Act requires the Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and, potentially, an environmental impact statement. The Coastal Zone Management Act, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and gas development. In obtaining various approvals from the Department of Interior, we must certify that we will conduct our activities in a manner consistent with these regulations.

Employees

As of December 31, 2008, we had 470 full-time employees, including 29 senior level geoscientists and 45 petroleum engineers. Our employees are not represented by any labor unions. We consider our relations with our employees to be satisfactory and have never experienced a work stoppage or strike.

Available Information

We maintain a website at the address www.whiting.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. We make available free of charge (other than an investor's own Internet access charges) through our website our Annual Report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and amendments to these reports, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission.

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Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Annual Report on Form 10-K, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

Oil and natural gas prices are very volatile. An extended period of oil and natural gas prices similar to or below the prices in effect at December 31, 2008 may adversely affect our business, financial condition, results of operations or cash flows.

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity;
- the level of global oil and gas exploration and production activity;
- the level of global oil and gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and gas in captive market areas; and
- the price and availability of alternative fuels.

Furthermore, 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 worldwide. 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, actual and forecasted prices for 2009 have declined since year-end.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve bookings. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending or borrow any such shortfall. Lower oil and natural gas prices may also 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.

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

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our development, exploitation, production and exploration activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "— Reserve estimates depend on many assumptions that may turn out to be inaccurate . . ." later in this Item for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and CO_2;
- equipment failures or accidents;
- adverse weather conditions, such as freezing temperatures, hurricanes and storms;
- reductions in oil and natural gas prices; and
- title problems.

Prospects that we decide to drill may not yield oil or gas in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this Annual Report on Form 10-K. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. 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 gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flowrates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, from more fully explored prospects, or from producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2008, we had identified a drilling inventory of over 1,400 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline and we may incur impairment charges if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. During the fourth quarter of 2008, we recorded a $10.9 million non-cash charge for the partial impairment of unproved properties in the central Utah Hingeline play. We may also incur such impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO2 into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO2. Our CO2 contracts permit the suppliers to reduce the amount of CO2 they provide to us in certain circumstances. If this occurs, we may not have sufficient CO2 to produce oil and natural gas in the manner or to the extent that we anticipate. These contracts are also structured as “take-or-pay” arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO2 as part of our enhanced recovery techniques.

The development of the proved undeveloped reserves in the North Ward Estes and Postle fields may take longer and may require higher levels of capital expenditures than we currently anticipate.

As of December 31, 2008, undeveloped reserves comprised 46.5% of the North Ward Estes field’s total estimated proved reserves and 16.8% of the Postle field’s total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $410.1 million at the North Ward Estes field and $84.5 million at the

Postle field. Together, these fields encompass 58% of our total estimated future development costs of $857.1 million related to proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO_2 injection installations, the success of which is less predictable than traditional development techniques. Therefore, ultimate recoveries from these fields may not match current expectations.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties.

Accounting rules require that we review periodically the carrying value of our oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, which may include depressed oil and natural gas prices, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and gas properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in this report.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, 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 from our proved reserves, as referred to in this report, is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2008 would have decreased from $1,376.4 million to $1,366.0 million. If oil prices decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2008 would have decreased from $1,376.4 million to $1,326.1 million.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of December 31, 2008, we had $620.0 million in borrowings and $2.8 million in letters of credit outstanding under Whiting Oil and Gas' credit agreement with $277.2 million of available borrowing capacity, as well as $620.0 million of senior subordinated notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas' credit agreement.

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Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas' credit agreement may be at variable rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas' credit agreement is periodically redetermined based on an evaluation of our reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our debt under the credit agreement.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We may not be able to generate sufficient cash flow to pay the interest on our debt or future borrowings, and equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including Whiting Oil and Gas' credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indentures governing our senior subordinated notes and Whiting Oil and Gas' credit agreement contain various restrictive covenants that may limit our management's discretion in certain respects. In particular, these agreements will limit our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our subordinated debt;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
-

enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;

- consolidate, merge or transfer all or substantially all of the assets of us and our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

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In addition, Whiting Oil and Gas' credit agreement requires us to maintain a debt to EBITDAX ratio (as defined in the credit agreement) of less than 3.5 to 1 and a working capital ratio of greater than 1 to 1. Also, the indentures under which we issued our senior subordinated notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas' credit agreement. A substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants.

If we fail to comply with the restrictions in the indentures governing our senior subordinated notes or Whiting Oil and Gas' credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Our exploration and development operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures through a combination of equity and debt issuances, bank borrowings and internally generated cash flows. We intend to finance future capital expenditures with cash flow from operations and existing financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our bank credit agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

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Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities related to future acquisitions.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes a continuing acquisition program. From 2004 through 2008, we completed 13 separate acquisitions of producing properties with a combined purchase price of $1,823.8 million for estimated proved reserves as of the effective dates of the acquisitions of 226.9 MMBOE. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

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Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

The differential between the NYMEX or other benchmark price of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount to the relevant benchmark prices such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

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Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. Thus, some of our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

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

In connection with our continued development of oil and gas properties, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in these properties, caused by transportation capacity constraints, curtailment of production or the interruption of transporting oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends 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. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Additionally, entering into arrangements for these services exposes us to the risk that third parties will default on their obligations under such arrangements. Our failure to obtain such services on acceptable terms or the default by a third party on their obligation to provide such services could materially harm our business. We may be required to shut in wells for a lack of a market or because access to gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- unitization and pooling of properties; and
- taxation.

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Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

Our operations may incur substantial liabilities to comply with environmental laws and regulations.

Our oil and gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities, and concentration of materials that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas; and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Federal law and some state laws also allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position, or financial condition as well as those of the oil and gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases”, including carbon dioxide and methane, may be contributing to warming of the Earth’s atmosphere. In response to such studies, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider legislation to regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emission of these gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court’s decision on April 2, 2007 in Massachusetts, et al. v. EPA, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court’s holding in Massachusetts that greenhouse gases fall under the federal Clean Air Act’s definition of “air pollutant” may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. More recently, in July 2008, the EPA released an “Advance Notice of Proposed Rulemaking,” regarding possible future regulation of greenhouse gases under the Clean Air Act. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we operate could adversely affect our operations by increasing costs. The cost increases would result from the potential new requirements to install additional emission control equipment and by increasing our monitoring and record-keeping burden.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.

The loss of senior management or technical personnel could adversely affect us.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, our Chairman, President and Chief Executive Officer; James T. Brown, our Senior Vice President; Rick A. Ross, our Vice President, Operations; Peter W. Hagist, our Vice President, Permian Operations; J. Douglas Lang, our Vice President, Reservoir Engineering/Acquisitions; David M. Seery, our Vice President of Land; Michael J. Stevens, our Vice President and Chief Financial Officer; or Mark R. Williams, our Vice President, Exploration and Development, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis or within our budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Competition in the oil and gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income.

We enter into hedging transactions of our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas forward sales contracts, primarily costless collars, placed with major financial institutions. As of December 31, 2008, we had contracts, which include our 24.2% share of the Whiting USA Trust I hedges, covering the sale in 2009 of between 489,190 and 556,129 barrels of oil per month and between 44,874 and 52,353 MMBtu of natural gas per month. All our oil hedges will expire by November 2013, and all our natural gas hedges will expire by December 2012. See “Quantitative and Qualitative Disclosure about Market Risk” for pricing and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we may otherwise receive from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

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Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties and Projects

Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of December 31, 2008, the Permian Basin region contributed 97.7 MMBOE (90% oil) of estimated proved reserves to our portfolio of operations, which represented 41% of our total estimated proved reserves and contributed 11.7 MBOE/d of average daily production in December 2008.

North Ward Estes Field. The North Ward Estes field includes six base leases with 100% working interest in approximately 58,000 gross and net acres in Ward and Winkler Counties, Texas. The Yates Formation at 2,600 feet is the primary producing zone with additional production from other zones including the Queen at 3,000 feet. In the North Ward Estes field, the estimated proved reserves as of December 31, 2008 were 29% PDP, 25% PDNP and 46% PUD.

The North Ward Estes field is responding positively to our water and CO2 floods, which we initiated in May 2007. As of December 31, 2008, we were injecting 123 MMcf/d of CO2 in this field. Production from the field has increased 29% from 5.1 MBOE/d in December 2007 to 6.6 MBOE/d in December 2008. In this field, we are developing new and reactivated wells for water and CO2 injection and production purposes.

Keystone South, Martin and Flying W Fields. We operate these three fields located on the Western edge of the Midland Basin. Production is from the Clearfork Formation, with additional production from the Wichita, Wolfcamp, Devonian, Silurian, McKee and Ellenburger Formations. During 2008, we drilled three wells in the Martin field and ten wells in the Keystone South field. The Keystone drilling program was in part to re-configure the waterflood and to drill additional wells into a Devonian structure on the east side of the lease that was discovered during 2007.

Rocky Mountain Region

Our Rocky Mountain operations include assets in the states of North Dakota, Montana, Colorado, Utah, Wyoming and California. As of December 31, 2008, our estimated proved reserves in the Rocky Mountain region were 83.2 MMBOE (59% oil), which represented 35% of our total estimated proved reserves and contributed 27.7 MBOE/d of average daily production in December 2008.

Sanish Field. Our Sanish area in Mountrail County, North Dakota encompasses approximately 125,600 gross (83,600 net) acres. December 2008 net production in the Sanish field averaged 7.5 MBOE/d, an 832% increase from 0.8 MBOE/d in December 2007. As of February 13, 2009, we have participated in 69 wells (39 operated) that target the Bakken formation, of which 54 are producing, eight are in the process of completion and seven are being drilled. Of these operated wells, 23 were completed in 2008. In order to process the produced gas stream from the Sanish wells, we constructed and brought on stream the Robinson Lake Gas Plant. The first phase of this plant began processing gas in May 2008, and in December 2008 we completed the construction of the second phase. We expect the 17-mile oil line connecting the Sanish field to the Enbridge pipeline in Stanley, North Dakota to be in service at the end of the second quarter of 2009.

Parshall Field. Immediately east of the Sanish field is the Parshall field, where we own interests in approximately 73,800 gross (18,300 net) acres. Our net production from the Parshall field averaged 6.7 MBOE/d in December 2008, a 345% increase from 1.5 MBOE/d in December 2007. As of February 13, 2009, we have participated in 97 Bakken wells, the majority of which are operated by EOG Resources, Inc., of which 86 are producing, seven are in the process of completion and four are drilling. Of these wells, 64 were completed in 2008.

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Lewis & Clark Prospect. We have assembled approximately 181,200 gross (111,500 net) acres in our Lewis & Clark prospect along the Bakken Shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over pressured, and has charged reservoir zones within the immediately underlying Three Forks formation.

Flat Rock Field. We acquired the Flat Rock Field in May 2008 and took over operations June 1, 2008. In the Flat Rock field area in Uintah County, Utah, we have an acreage position consisting of approximately 22,000 gross (11,500 net) acres. We recently completed two wells in the Entrada formation that had initial gross production rates of 4.1 MMcf/d and 9.3 MMcf/d.

Sulphur Creek Field. In the Sulphur Creek field in Rio Blanco County, Colorado in the Piceance Basin, we own approximately 8,400 gross (4,300 net) acres in the Sulphur Creek field area. We drilled three wells in Jimmy Gulch in 2008. As of February 13, 2009, the three wells were producing at a combined net rate of 3.0 MMcf/d.

Hatfield Prospect. In southern Wyoming in the Hatfield prospect area, we have a large acreage position covering over 80-square miles and encompassing approximately 53,200 gross (31,900 net) acres. In this area, cumulative production from three vertical Niobrara wells drilled by other operators has ranged from approximately 22.0 MBOE to 124.0 MBOE per well. In September 2008, we drilled a vertical well to test the Niobrara formation, as well as a deeper zone. During drilling operations, oil flowed to the surface and oil shows were seen in the drill cuttings, and we are currently conducting completion operations on this well. We believe that current horizontal drilling techniques will improve recovery compared to vertical drilling used at historic wells in this area.

Hatch Point Prospect. At our Hatch Point prospect in San Juan County, Utah in the Paradox Basin, we have an exploratory horizontal well planned for 2009 in the Cane Creek zone at an estimated cost of approximately $6.5 million ($3.5 million net).

Utah Hingeline. We own a 15%, non-operated, working interest in approximately 170,000 acres of leasehold in the central Utah Hingeline play. This acreage covers several prospect leads which have been identified along trend with the Covenant field discovery in Sevier County, Utah. As part of our acquisition of this property, the operator agreed to pay 100% of our drilling and completion costs for the first three wells in the project. The three wells were drilled, but the hydrocarbons encountered were not determined to be economic, resulting in dry holes for all three wells.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. As of December 31, 2008, the Mid-Continent region contributed 39.1 MMBOE (95% oil) of proved reserves to our portfolio of operations, which represented 16% of our total estimated proved reserves and contributed 7.2 MBOE/d of average daily production in December 2008. The majority of the proved value within our Mid-Continent operations is related to properties in the Postle field.

Postle Field. The Postle field, located in Texas County, Oklahoma, includes five producing units and one producing lease covering a total of approximately 25,600 gross (24,200 net) acres. Four of the units are currently active CO2 enhanced recovery projects. Our expansion of the CO2 flood at the Postle field continues to generate positive results. As of December 31, 2008, we were injecting 142 MMcf/d of CO2 in this field. Production from the field has increased 22% from a net 5.8 MBOE/d in December 2007 to a net 7.1 MBOE/d in December 2008. Operations are underway to expand CO2 injection into the northern part of the fourth unit, HMU, and to optimize flood patterns in the existing CO2 floods. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells. In the Postle field, the estimated proved reserves as of December 31, 2008 were 61% PDP, 22% PDNP and 17% PUD.

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We are the sole owner of the Dry Trails Gas Plant located in the Postle field. This gas processing plant utilizes a membrane technology to separate CO_2 gas from the produced wellhead mixture of hydrocarbon and CO_2 gas, so that the CO_2 gas can be re-injected into the producing formation.

In addition to the producing assets and processing plant, we have a 60% interest in the 120-mile TransPetco operated CO_2 transportation pipeline, thereby assuring the delivery of CO_2 to the Postle field at a fair tariff. A long-term CO_2 purchase agreement was executed in 2005 to provide the necessary CO_2 for the expansion planned in the field.

Gulf Coast Region

Our Gulf Coast operations include assets located in Texas, Louisiana and Mississippi. As of December 31, 2008, the Gulf Coast region contributed 10.1 MMBOE (31% oil) of proved reserves to our portfolio of operations, which represented 4% of our total estimated proved reserves and contributed 5.0 MBOE/d of average daily production in December 2008.

Edwards Trend. We own acreage in the Word North, Yoakum, Kawitt, Sweet Home, and Three Rivers fields along the Edwards Trend in Karnes, Dewitt and Lavaca Counties, Texas. In 2007, we farmed out a large part of our acreage position to another operator who is developing the Edwards Trend with horizontal wellbores. Under the terms of the farmout agreement, we back in for a 25% working interest at payout of the well. In 2008, we participated in three wells under this agreement.

Michigan Region

As of December 31, 2008, our estimated proved reserves in the Michigan region were 9.0 MMBOE (27% oil), and our December 2008 daily production averaged 3.5 MBOE/d. Production in Michigan can be divided into two groups. The majority of the reserves are in non-operated Antrim Shale wells located in the northern part of the state. The remainder of the Michigan reserves are typified by more conventional oil and gas production located in the central and southern parts of the state. We also operate the West Branch and Reno gas processing plants. The West Branch Plant gathers production from the Clayton, West Branch and other smaller fields.

Clayton Unit. Clayton Unit production is primarily from the Prairie du Chien and Glenwood at a depth of around 11,000 feet. During 2008, two successful wells were drilled in the Clayton Unit.

Marion 3-D Project. The Marion Prospect, located in Missauke, Clare and Oceola Counties, Michigan, covers approximately 17,700 gross (14,400 net) acres. Our analysis of seismic data has identified three drillable prospects and we are currently formulating our drilling plans for this area.

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Acreage

The following table summarizes gross and net developed and undeveloped acreage by state at December 31, 2008. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
California	35,747	10,724	2,284	34	38,031	10,758
Colorado	36,253	18,053	32,379	8,429	68,632	26,482
Louisiana	41,156	10,729	4,960	2,619	46,116	13,348
Michigan	136,236	59,647	47,671	26,222	183,907	85,869
Montana	41,449	13,425	33,240	14,554	74,689	27,979
North Dakota	258,161	135,280	343,815	192,232	601,976	327,512
Oklahoma	87,248	55,108	2,692	2,321	89,940	57,429
Texas	219,776	136,151	88,049	61,897	307,825	198,048
Utah	19,560	11,743	262,031	62,858	281,591	74,601
Wyoming	100,830	55,088	72,610	48,611	173,440	103,699
Other*	15,976	8,933	2,399	999	18,375	9,932
Total	992,392	514,881	892,130	420,776	1,884,522	935,657

* Other includes Alabama, Arkansas, Kansas, Mississippi and New Mexico.

Production History

The following table presents historical information about our produced oil and gas volumes:

	Year Ended December 31,		
	2008	2007	2006
Oil production (MMBbls)	12.4	9.6	9.8
Natural gas production (Bcf)	30.4	30.8	32.1
Total production (MMBOE)	17.5	14.7	15.2
Daily production (MBOE/d)	47.9	40.3	41.5
Average sales prices:			
Oil (per Bbl)	$ 86.99	$ 64.57	$ 57.27
Effect of oil hedges on average price (per Bbl)	(8.58)	(2.21)	(0.95)
Oil net of hedging (per Bbl)	$ 78.41	$ 62.36	$ 56.32
Natural gas (per Mcf)	$ 7.68	$ 6.19	$ 6.59
Effect of natural gas hedges on average price (per Mcf)	-	-	0.06
Natural gas net of hedging (per Mcf)	$ 7.68	$ 6.19	$ 6.65
Per BOE data:			
Sales price (net of hedging)	$ 69.06	$ 53.57	$ 50.52
Lease operating expenses	$ 13.77	$ 14.20	$ 12.12
Production taxes	$ 5.00	$ 3.56	$ 3.11
Depreciation, depletion and amortization expenses	$ 15.84	$ 13.11	$ 10.74
General and administrative expenses	$ 3.52	$ 2.66	$ 2.49

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Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by region at December 31, 2008. A net well is our percentage ownership of a gross well. Wells in which our interest is limited to royalty and overriding royalty interests are excluded.

	Oil Wells		Natural Gas Wells		Total Wells(1)	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	3,611	1,687	387	121	3,998	1,808
Rocky Mountains	1,953	378	480	241	2,433	619
Mid-Continent	551	268	205	36	756	304
Gulf Coast	92	54	481	116	573	170
Michigan	80	35	1,031	401	1,111	436
Total	6,287	2,422	2,584	915	8,871	3,337

(1) 102 wells are multiple completions. These 102 wells contain a total of 222 completions. One or more completions in the same bore hole are counted as one well.

Drilling Activity

We are engaged in numerous drilling activities on properties presently owned and intend to drill or develop other properties acquired in the future. The following table sets forth our drilling activity for the last three years. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2008:						
Development	283	20	303	113.3	9.2	122.5
Exploratory	2	3	5	1.9	1.3	3.2
Total	285	23	308	115.2	10.5	125.7
2007:						
Development	262	5	267	128.6	3.8	132.4
Exploratory	9	1	10	6.1	0.1	6.2
Total	271	6	277	134.7	3.9	138.6
2006:						
Development	401	14	415	300.6	9.0	309.6
Exploratory	17	5	22	10.2	2.3	12.5
Total	418	19	437	310.8	11.3	322.1

As of February 13, 2009, nine operated drilling rigs and 37 operated workover rigs were active on our properties. We were also participating in the drilling of four non-operated wells, all of which are located in the Parshall field. The breakdown of our operated rigs is as follows:

Region	Drilling	Workover
Rocky Mountain	8	5

Permian	0	2
Mid-Continent/Michigan	0	3
North Ward Estes	0	20
Postle	1	6
Gulf Coast	0	1
Total	9	37

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Item 3. Legal Proceedings

Whiting is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management's opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

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

No matters were submitted to a vote of security holders during the fourth quarter of 2008.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 16, 2009, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	62	Chairman, President and Chief Executive Officer
James T. Brown	56	Senior Vice President, Operations
Bruce R. DeBoer	56	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	38	Vice President, Human Resources
J. Douglas Lang	59	Vice President, Reservoir Engineering/Acquisitions
Rick A. Ross	50	Vice President, Operations
David M. Seery	54	Vice President, Land
Michael J. Stevens	43	Vice President and Chief Financial Officer
Mark R. Williams	52	Vice President, Exploration and Development
Brent P. Jensen	39	Controller and Treasurer

The following biographies describe the business experience of our executive officers:

James J. Volker joined us in August 1983 as Vice President of Corporate Development and served in that position through April 1993. In March 1993, he became a contract consultant to us and served in that capacity until August 2000, at which time he became Executive Vice President and Chief Operating Officer. Mr. Volker was appointed President and Chief Executive Officer and a director in January 2002 and Chairman of the Board in January 2004. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has over 30 years of experience in the oil and gas industry. Mr. Volker has a degree in finance from the University of Denver, an MBA from the University of Colorado and has completed H. K. VanPoolen and Associates' course of study in reservoir engineering.

James T. Brown joined us in May 1993 as a consulting engineer. In March 1999, he became Operations Manager, in January 2000, he became Vice President of Operations, and in May 2007, he became Senior Vice President of Operations. Mr. Brown has over 30 years of oil and gas experience in the Rocky Mountains, Gulf Coast, California and Alaska. Mr. Brown is a graduate of the University of Wyoming, with a Bachelor's Degree in civil engineering, and the University of Denver, with an MBA.

Bruce R. DeBoer joined us as our Vice President, General Counsel and Corporate Secretary in January 2005. From January 1997 to May 2004, Mr. DeBoer served as Vice President, General Counsel and Corporate Secretary of Tom Brown, Inc., an independent oil and gas exploration and production company. Mr. DeBoer has over 20 years of experience in managing the legal departments of several independent oil and gas companies. He holds a Bachelor of Science Degree in Political Science from South Dakota State University and received his J.D. and MBA degrees from the University of South Dakota.

Heather M. Duncan joined us in February 2002 as Assistant Director of Human Resources and in January 2003 became Director of Human Resources. In January 2008, she was appointed Vice President of Human Resources. Ms. Duncan has 12 years of human resources experience in the oil and gas industry. She holds a Bachelor of Arts Degree in Anthropology and an MBA from the University of Colorado. She is a certified Professional in Human Resources.

J. Douglas Lang joined us in December 1999 as Senior Acquisition Engineer and became Manager of Acquisitions and Reservoir Engineering in January 2004 and Vice President—Reservoir Engineering/ Acquisitions in October 2004. His over 30 years of acquisition and reservoir engineering experience has included staff and managerial positions with Amoco, Petro-Lewis, General Atlantic Resources, UMC Petroleum and Ocean Energy. Mr. Lang holds a Bachelor's Degree in Petroleum Engineering from the University of Wyoming and an MBA from the University of Denver. He is a registered Professional Engineer and has served on the national Board of Directors of the Society of Petroleum Evaluation Engineers.

Rick A. Ross joined us in March 1999 as an Operations Manager. In May 2007, he became Vice President of Operations. Mr. Ross has over 25 years of oil and gas experience. Mr. Ross holds a Bachelor of Science Degree in Mechanical Engineering from the South Dakota School of Mines and Technology.

David M. Seery joined us as our Manager of Land in July 2004 as a result of our acquisition of Equity Oil Company, where he was Manager of Land and Manager of Equity's Exploration Department, positions he had held for more than five years. He became our Vice President of Land in January 2005. Mr. Seery has 27 years of land experience including staff and managerial positions with Marathon Oil Company. Mr. Seery holds a Bachelor of Science Degree in Business Management from the University of Montana. He is a Registered Land Professional and held various duties with the Denver Association of Petroleum Landmen.

Michael J. Stevens joined us in May 2001 as Controller, and became Treasurer in January 2002 and became Vice Pr