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.

TABLE OF CONTENTS

Table of Contents

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.

Table of Contents

"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.

Table of Contents

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:

	Proved Reserves(1)					
Core Area	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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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 CO2 floods. This provides us with the ability to pursue other CO2 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

11

Table of Contents

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:

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

16

Table of Contents

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.

Table of Contents

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 CO_2 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 CO_2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO_2. Our CO_2 contracts permit the suppliers to reduce the amount of CO_2 they provide to us in certain circumstances. If this occurs, we may not have sufficient CO_2 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 CO_2 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 CO2 injection installations, the success of which is less predictable than traditional development techniques. Therefore, ultimate recoveries from these fields may not match current expectations.

Table of Contents

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.

19

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

26

Table of Contents

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.

Table of Contents

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.

28

Table of Contents

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 CO2 gas from the produced wellhead mixture of hydrocarbon and CO2 gas, so that the CO2 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 CO2 transportation pipeline, thereby assuring the delivery of CO2 to the Postle field at a fair tariff. A long-term CO2 purchase agreement was executed in 2005 to provide the necessary CO2 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.

Table of Contents

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

30

Table of Contents

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

Table of Contents

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.

Table of Contents

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 President and Chief Financial Officer in March 2005. From 1993 until May 2001, he served in various positions including Chief Financial Officer, Controller, Secretary and Treasurer at Inland Resources Inc., a company engaged in oil and gas exploration and development. He spent seven years in public accounting with Coopers & Lybrand in Minneapolis, Minnesota. He is a graduate of Mankato State University of Minnesota and is a Certified Public Accountant.

Mark R. Williams joined us in December 1983 as Exploration Geologist, becoming Vice President of Exploration and Development in December 1999. He has 26 years of experience in the oil and gas industry and his areas of primary technical expertise are in sequence stratigraphy, seismic interpretation and petroleum economics. Mr. Williams is a graduate of the Colorado School of Mines with a Master's Degree in geology and holds a Bachelor's Degree in geology from the University of Utah.

Brent P. Jensen joined us in August 2005 as Controller, and he became Controller and Treasurer in January 2006. He was previously with PricewaterhouseCoopers L.L.P. in Houston, Texas, where he held various positions in their oil and gas audit practice since 1994, which included assignments of four years in Moscow, Russia and three years in Milan, Italy. He has 15 years of oil and gas accounting experience and is a Certified Public Accountant. Mr. Jensen holds a Bachelor of Arts degree from the University of California, Los Angeles.

Executive officers are elected by, and serve at the discretion of, the Board of Directors. There are no family relationships between any of our directors or executive officers.

Table of Contents

PART II

Item 5. Market for the Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Whiting Petroleum Corporation’s common stock is traded on the New York Stock Exchange under the symbol “WLL.” The following table shows the high and low sale prices for our common stock for the periods presented.

	High	Low
Fiscal Year Ended December 31, 2008		
Fourth Quarter (Ended December 31, 2008)	$ 69.58	$ 24.36
Third Quarter (Ended September 30, 2008)	$ 112.42	$ 62.09
Second Quarter (Ended June 30, 2008)	$ 108.53	$ 63.07
First Quarter (Ended March 31, 2008)	$ 66.19	$ 44.60
Fiscal Year Ended December 31, 2007		
Fourth Quarter (Ended December 31, 2007)	$ 59.06	$ 44.09
Third Quarter (Ended September 30, 2007)	$ 45.14	$ 35.85
Second Quarter (Ended June 30, 2007)	$ 47.50	$ 38.71
First Quarter (Ended March 31, 2007)	$ 46.04	$ 35.81

On February 16, 2009, there were 887 holders of record of our common stock.

We have not paid any dividends since we were incorporated in July 2003. We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our financial position, cash flows, results of operations, capital requirements and investment opportunities. In addition, the agreements governing our indebtedness prohibit us from paying dividends.

Information relating to compensation plans under which our equity securities are authorized for issuance is set forth in Part III, Item 12 of this Annual Report on Form 10-K.

The following information in this Item 5 of this Annual Report on Form 10-K is not deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares on a cumulative basis changes since December 31, 2003 in (a) the total stockholder return on our common stock with (b) the total return on the Standard & Poor’s Composite 500 Index and (c) the total return on the Dow Jones US Oil Companies, Secondary Index. Such changes have been measured by dividing (a) the sum of (i) the amount of dividends for the measurement period, assuming dividend reinvestment, and (ii) the difference between the price per share at the end of and the beginning of the measurement period, by (b) the price per share at the beginning of the measurement period. The graph assumes $100 was invested on December 31, 2003 in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones US Oil Companies, Secondary Index.

Table of Contents

	12/31/03	12/31/04	12/31/05	12/31/06	12/31/07	12/31/08
Whiting Petroleum Corporation	$ 100	$ 164	$ 217	$ 253	$ 313	$ 182
Standard & Poor’s Composite 500 Index	100	109	112	128	132	81
Dow Jones US Oil Companies, Secondary Index	100	140	230	241	344	204

Table of Contents

Item 6. Selected Financial Data

The consolidated income statement information for the years ended December 31, 2008, 2007 and 2006 and the consolidated balance sheet information at December 31, 2008 and 2007 are derived from our audited financial statements included elsewhere in this report. The consolidated income statement information for the years ended December 31, 2005 and 2004 and the consolidated balance sheet information at December 31, 2006, 2005 and 2004 are derived from audited financial statements that are not included in this report. Our historical results include the results from our recent acquisitions beginning on the following dates: Flat Rock Natural Gas Field, May 30, 2008; Utah Hingeline, August 29, 2006; Michigan Properties, August 15, 2006; North Ward Estes and Ancillary Properties, October 4, 2005; Postle Properties, August 4, 2005; Limited Partnership Interests, June 23, 2005; Green River Basin, March 31, 2005; Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; Wyoming and Utah, September 30, 2004; Louisiana and Texas, August 16, 2004; Mississippi, November 3, 2004; and additional Permian Basin interest, December 31, 2004.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(dollars in millions, except per share data)				
Consolidated Statements of Income Information:					
Revenues and other income:					
Oil and natural gas sales	$ 1,316.5	$ 809.0	$ 773.1	$ 573.2	$ 281.1
Loss on oil and natural gas hedging activities	(107.6)	(21.2)	(7.5)	(33.4)	(4.9)
Gain on sale of oil and gas properties	—	29.7	12.1	—	1.0
Gain on sale of marketable securities	—	—	—	—	4.8
Amortization of deferred gain on sale	12.1	—	—	—	—
Interest income and other	1.1	1.2	1.1	0.6	0.1
Total revenues and other income	1,222.1	818.7	778.8	540.4	282.1
Costs and expenses:					
Lease operating	241.2	208.9	183.6	111.6	54.2
Production taxes	87.5	52.4	47.1	36.1	16.8
Depreciation, depletion and amortization	277.5	192.8	162.8	97.6	54.0
Exploration and impairment	55.3	37.3	34.5	16.7	6.3
General and administrative	61.7	39.0	37.8	30.6	19.2
Change in Production Participation Plan liability	32.1	8.6	6.2	9.7	1.7

Interest expense		65.1		72.5		73.5		42.0		15.9
Gain on mark-to-market derivatives		(7.1)		—		—		—		—
Total costs and expenses		813.3		611.5		545.5		344.3		168.1
Income before income taxes		408.8		207.2		233.3		196.1		114.0
Income tax expense		156.7		76.6		76.9		74.2		44.0
Net income	$	252.1	$	130.6	$	156.4	$	121.9	$	70.0
Net income per common share, basic	$	5.96	$	3.31	$	4.26	$	3.89	$	3.38
Net income per common share, diluted	$	5.94	$	3.29	$	4.25	$	3.88	$	3.38
Other Financial Information:										
Net cash provided by operating activities	$	763.0	$	394.0	$	411.2	$	330.2	$	134.1
Net cash used in investing activities	$	(1,134.9)	$	467.0	$	527.6	$	1,126.9	$	524.4
Net cash provided by financing activities	$	366.8	$	77.3	$	116.4	$	805.5	$	338.4
Ratio of earnings to fixed charges (1)		6.92x		3.65x		4.14x		5.64x		8.01x
Capital expenditures	$	1,330.9	$	519.6	$	552.0	$	1,126.9	$	530.6
Consolidated Balance Sheet Information:										
Total assets	$	4,029.1	$	2,952.0	$	2,585.4	$	2,235.2	$	1,092.2
Total debt	$	1,239.8	$	868.2	$	995.4	$	875.1	$	328.4
Stockholders' equity	$	1,808.8	$	1,490.8	$	1,186.7	$	997.9	$	612.4

(1) For the purpose of calculating the ratio of earnings to fixed charges, earnings consist of income before income taxes and income from equity investees, plus fixed charges, distributed income from equity investees, and amortization of capitalized interest, less capitalized interest. Fixed charges consist of interest expensed, interest capitalized, amortized premiums, discounts and capitalized expenses related to indebtedness, and an estimate of interest within rental expense.

Table of Contents

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Unless the context otherwise requires, the terms "Whiting," "we," "us," "our" or "ours" when used in this Item refer to Whiti Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation, Equity Oil Company and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in oil and gas 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. Prior to 2006, we generally emphasized the acquisition of properties that increased our production levels and provided upside potential through further development. Since 2006, we have focused primarily on organic drilling activity and on the development of previously acquired properties, specifically on projects that we believe provide the opportunity for repeatable successes and production growth. We believe the combination of acquisitions, subsequent development and organic drilling provides us a broad set of growth alternatives and allows us to direct our capital resources to what we believe to be the most advantageous investments.

As demonstrated by our recent capital expenditure programs, 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. 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.

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that established a presence in a new area of interest or that have complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis. We sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Oil and natural gas prices have fallen significantly since their third quarter 2008 levels. For example, 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, the actual and forecasted prices for 2009 have also declined since year-end. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may materially and adversely affect our future business, financial position, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and the oil and natural gas reserves that we can economically produce. Lower oil and 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.

Table of Contents

2008 Highlights and Future Considerations

Operational Highlights. Our Sanish field in Mountrail County, North Dakota targets the Bakken formation. December 2008 net production in the Sanish field averaged 7.5 MBOE/d in December 2008, an 832% increase from 0.8 MBOE/d in December 2007. In order to separate the natural gas liquids ("NGLs") from the natural gas processed 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 the second phase was completed in December 2008. Immediately east of the Sanish field is the Parshall field, where net production averaged 6.7 MBOE/d in December 2008, a 341% increase from 1.5 MBOE/d in December 2007.

We continue to have significant development and related infrastructure activity on the Postle and North Ward Estes fields acquired in 2005, which have resulted in reserve and production increases. Our expansion of the CO2 flood at both fields continues to generate positive results. During 2008, we incurred $325.1 million of development expenditures on these two projects.

The Postle field is located in Texas County, Oklahoma. Four of our five producing units are currently under active CO2 enhanced recovery projects. 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 under way 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.

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 a net 5.1 MBOE/d in December 2007 to a net 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. Additionally, we plan to install oil, gas and water processing facilities in five phases through 2015, and we estimate that the first three phases will be substantially complete by December 2009.

The Sulphur Creek field in Rio Blanco County, Colorado in the Piceance Basin includes the Boies Ranch and Jimmy Gulch prospects. We expect our development in this area during 2009 will be focused on the Jimmy Gulch lease which targets the shallow Wasatch zone. 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.

2009 Capital Budget and Major Development Areas. 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. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would adjust our capital budget accordingly. Our 2009 capital budget currently is allocated among our major development areas as indicated in the chart below. We may use a portion of the balance of the net proceeds from our February 2009 common stock offering to further develop these projects; or, in the event of further oil and gas price declines, to keep our bank debt at lower levels.

Table of Contents

Of our existing potential projects, we believe these present the opportunity for the highest return and most efficient use of our capital expenditures.

Development Area	2009 Planned Capital Expenditures (In millions)	
Northern Rockies	$	242.3
CO2 Projects (1)		129.3
Central Rockies		72.4
Other (2)		30.0
Total	$	474.0

(1) 2009 planned capital expenditures at our CO2 projects include $36.9 million for purchased CO2 at North Ward Estes and $15.3 million for Postle CO2 purchases.
(2) Comprised primarily of exploration salaries, lease delay rentals and seismic and other development.

Subsequent Event

In February 2009, we completed a public offering of our common stock under our existing shelf registration statement, selling 8,000,000 shares of common stock at a price of $29.00 per share and providing net proceeds of $222.2 million after underwriters' discounts and commissions and estimated offering expenses. Pursuant to the exercise of the underwriters' overallotment option, we sold an additional 450,000 shares of common stock at $29.00 per share, providing net proceeds of $12.5 million. We used the net offering proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement. We plan to use a portion of the increased credit availability to fund capital expenditures in our 2009 capital budget. Had the common stock issuance occurred at the beginning of 2008, the number of basic and diluted shares used in the computations of earnings per share would have been 50,759,517 and 50,897,256, respectively, for the year ended December 31, 2008.

Acquisitions

Flat Rock Natural Gas Field. 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.

Utah Hingeline. On August 29, 2006, we acquired a 15% working interest in approximately 170,000 acres of unproved properties in the central Utah Hingeline play for $25.0 million. No producing properties or proved reserves were associated with this acquisition. 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.

Michigan Properties. On August 15, 2006, we acquired 65 producing properties, a gathering line, gas processing plant and approximately 30,400 net acres of leasehold held by production in Michigan. The purchase price was $26.0 million for estimated proved reserves of 1.4 MMBOE as of the acquisition effective date of May 1, 2006, resulting in a cost of $18.55 per BOE of estimated proved reserves. Proved developed reserve quantities represented 99% of the total proved reserves acquired. The average daily production from the properties was 0.6 MBOE/d as of the acquisition effective date.

Table of Contents

Divestitures

Whiting USA Trust I. 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, and 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 offering net 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% (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% (3.1 MBOE/d) of our March 2008 average daily net production.

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.

During 2006, we sold our interests in several non-core oil and gas producing properties for an aggregate amount of $24.4 million in cash for total estimated proved reserves of 1.4 MMBOE as of the divestitures' effective dates. The divested properties included interests in the Cessford field in Alberta, Canada; Permian Basin of West Texas and New Mexico; and the Ashley Valley field in Uintah County, Utah. The average daily net production from the divested property interests was 0.4 MBOE/d as of the dates of disposition, and we recognized a pre-tax gain on sale of $12.1 million related to these divestitures.

Table of Contents

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
Net production:			
Oil (MMBbls)	12.4	9.6	9.8
Natural gas (Bcf)	30.4	30.8	32.1
Total production (MMBOE)	17.5	14.7	15.2
Net sales (in millions):			
Oil (1)	$ 1,082.8	$ 618.5	$ 561.2
Natural gas (1)	233.7	190.5	211.9
Total oil and natural gas sales	$ 1,316.5	$ 809.0	$ 773.1
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
Average NYMEX price	$ 97.24	$ 72.30	$ 66.25
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
Average NYMEX price	$ 9.06	$ 6.86	$ 7.23
Cost and expense (per BOE):			
Lease operating expenses	$ 13.77	$ 14.20	$ 12.12
Production taxes	$ 5.00	$ 3.56	$ 3.11
Depreciation, depletion and amortization expense	$ 15.84	$ 13.11	$ 10.74
General and administrative expenses	$ 3.52	$ 2.66	$ 2.49

(1) Before consideration of hedging transactions.

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

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $507.5 million to $1,316.5 million in 2008 compared to 2007. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 30% between periods, while our natural gas sales volumes decreased 1%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area, in addition to increased production at our two large CO2 projects, Postle and North Ward Estes. Oil production from the Bakken increased 2,960 MBbl compared to 2007, while Postle oil production increased 380 MBbl and North Ward Estes oil production increased 265 MBbl over the same period in 2007. These production increases were partially offset by the Whiting USA Trust I (the "Trust") divestiture, which decreased oil production by 630 MBbl. The gas volume decline between periods was primarily the result of the Trust divestiture, which decreased gas production in 2008 by 2,920 MMcf, and property dispositions in the second half of 2007, which decreased gas production in 2008 by an additional 780 MMcf. These decreases were partially offset by incremental gas production of 2,885 MMcf from the Flat Rock acquisition and higher production in the Boies Ranch area of 1,505 MMcf. Our average price for oil before effects of hedging increased 35% between periods, and our average price for natural gas before effects of hedging increased 24%.

Table of Contents

Loss on Oil and Natural Gas Hedging Activities. Realized cash settlements on commodity derivatives that we have designated as cash flow hedges are recognized as (gain) loss on oil and natural gas hedging activities. During 2008, we incurred cash settlement losses of $107.6 million on such crude oil hedges, and during 2007 we incurred cash settlement losses of $21.2 million on these oil hedges. We incurred no cash settlement gains or losses during 2008 or 2007 on natural gas derivative contracts designated as cash flow hedges. See Item 7A, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil hedges as of January 1, 2009.

Gain on Sale of Properties. There was no gain or loss on the sale of properties during 2008. During 2007, however, we sold certain non-core properties for aggregate sales proceeds of $52.6 million, resulting in a pre-tax gain on sale of $29.7 million.

Amortization of Deferred Gain on Sale. In connection with the sale of 11,677,500 Trust units to the public and related oil and gas property conveyance on April 30, 2008, we recognized a deferred gain on sale of $100.0 million. This deferred gain is amortized to income over the life of the Trust on the units-of-production basis. During 2008, we recognized $12.1 million in income as amortization of deferred gain on sale.

Lease Operating Expenses. Our lease operating expenses during 2008 were $241.2 million, a $32.4 million or 16% increase over the same period in 2007. Our lease operating expenses per BOE decreased from $14.20 during 2007 to $13.77 during 2008. The decrease of 3% on a BOE basis was primarily caused by flush production from Bakken drilling, which was partially offset by inflation in the cost of oil field goods and services and a higher level of workover activity. Workovers amounted to $27.3 million in 2008, as compared to $17.4 million of workover activity during 2007.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for 2008 and 2007 were 6.7% and 6.5%, respectively, of oil and natural gas sales. The 2008 rate increased slightly from 2007 mainly due to successful wells completed in the North Dakota Bakken area during 2008, which carry an 11.5% production tax rate.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $84.6 million in 2008 as compared to 2007. The components of DD&A expense were as follows (in thousands):

	Year Ended December 31, 2008	2007
Depletion	$ 270,770	$ 186,838
Depreciation	3,439	3,123
Accretion of asset retirement obligations	3,239	2,850
Total	$ 277,448	$ 192,811

DD&A increased $84.6 million primarily due to $83.9 million in higher depletion expense between periods. Of this $83.9 million increase in depletion, $35.7 million relates to higher oil and gas volumes produced during 2008, while $48.2 million relates to our higher depletion rate in 2008. On a BOE basis, our DD&A rate increased by 21% from $13.11 for 2007 to $15.84 for 2008. The primary factors causing this rate increase were (i) $918.1 million in drilling expenditures incurred during the past twelve months, (ii) net oil and natural gas reserve reductions of 11.6 MMBOE during 2008, which were primarily attributable to a 39.0 MMBOE downward revision for lower oil and natural gas prices at December 31, 2008, and (iii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

Table of Contents

Exploration and Impairment Costs. Our exploration and impairment costs increased $17.9 million, as compared to 2007. The components of exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2008	2007
Exploration	$ 29,302	$ 27,344
Impairment	25,955	9,979
Total	$ 55,257	$ 37,323

Exploration costs increased $2.0 million during 2008 as compared to 2007 primarily due to higher exploration employee compensation costs and exploratory dry hole expense, which were partially offset by a decrease in geological and geophysical activity. During 2008, we drilled one exploratory dry hole in the Permian region and participated in two non-operated exploratory dry holes in the Rocky Mountains region totaling $3.6 million, while during 2007 we participated in a non-operated exploratory well in the Gulf Coast region that resulted in an insignificant amount of dry hole expense. Impairment expense is mainly related to the amortization of leasehold costs associated with individually insignificant unproved properties. Impairment expense in 2008 is higher than 2007 because the amount of unproved properties being amortized totaled $72.3 million as of December 31, 2008, as compared to $51.5 million as of December 31, 2007. Also lending to the increase in impairment during 2008 was a $10.9 million non-cash charge to impairment expense for the partial write-down of unproved properties in the central Utah Hingeline play. In the fourth quarter of 2008 based on poor drilling results, we determined that 1,873 net acres within our central Utah Hingeline position would no longer be evaluated, drilled or otherwise developed and should be written down accordingly.

General and Administrative Expenses. We report general and administrative expenses net of third party reimbursements and internal allocations. The components of general and administrative expenses were as follows (in thousands):

	Year Ended December 31,	
	2008	2007
General and administrative expenses	$ 103,231	$ 72,008
Reimbursements and allocations	(41,547)	(32,962)
General and administrative expenses, net	$ 61,684	$ 39,046

General and administrative expense before reimbursements and allocations increased $31.2 million to $103.2 million during 2008. The largest components of the increase related to (i) $20.1 million in higher accrued distributions under our Production Participation Plan ("Plan") between periods due to the net profits interest divestiture associated with the sale of 11,677,500 Trust units, and a higher level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) in 2008, and (ii) $9.1 million of additional employee compensation for personnel hired during the past twelve months along with general pay increases. The increase in reimbursements and allocations in 2008 was caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales remained constant at 5% for both 2008 and 2007.

Table of Contents

Interest Expense. The components of interest expense were as follows (in thousands):

	Year Ended December 31, 2008	2007
Senior Subordinated Notes	$ 43,461	$ 44,691
Credit Agreement	18,377	24,428
Amortization of debt issue costs and debt discount	4,801	5,022
Accretion of tax sharing liability	1,267	1,505
Other	301	522
Capitalized interest	(3,129)	(3,664)
Total interest expense	$ 65,078	$ 72,504

The decrease in interest expense of $7.4 million between years was mainly due to lower interest rates during 2008 on borrowings under our credit agreement. Our weighted average effective cash interest rate was 5.9% during 2008 compared to 7.2% during 2007. Our weighted average debt outstanding during 2008 was $1,049.4 million, while it was $964.4 million for 2007. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 6.3% during 2008 compared to 7.7% during 2007.

Change in Production Participation Plan Liability. For the year ended December 31, 2008, this non-cash expense was $32.1 million, an increase of $23.5 million as compared to 2007. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2009 under our Plan. Although payments take place over the life of the Plan’s oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan’s five-year vesting period. This expense in 2008 and 2007 primarily reflects (i) changes to future cash flow estimates stemming from the volatile commodity price environment during the past three years, (ii) 2008 drilling activity and property acquisitions, and (iii) employees’ continued vesting in the Plan. Due to the higher commodity price environment during 2008, we moved from using a five-year average of historical NYMEX prices to a three-year average when estimating the future payments to be made under this Plan. The average NYMEX prices used to estimate this liability increased by $24.63 for crude oil and $0.86 for natural gas for the year ended December 31, 2008, as compared to increases of $8.58 for crude oil and $0.67 for natural gas over the same period in 2007. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

Gain on Mark-to-Market Derivatives. During 2008, we entered into derivative contracts that we did not designate as cash flow hedges. Accordingly, these derivative contracts are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings. Cash flow is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded immediately to earnings as (gain) loss on mark-to-market derivatives. As a result of decreases mainly in oil prices, we recognized $4.2 million in unrealized mark-to-market derivative gains during 2008 and $0.9 million in realized cash settlement gains. We also recognized income of $1.9 million as a gain on mark-to-market derivatives for the ineffective portion of changes in fair value on our commodity derivatives designated as cash flow hedges.

Income Tax Expense. Income tax expense totaled $156.7 million in 2008 and $76.6 million for 2007. Our effective income tax rate increased from 37.0% for 2007 to 38.3% for 2008. Our effective income tax rate was higher in 2008 due to our drilling success in state jurisdictions having higher income tax rates and an increase in the amount of current income taxes paid in certain states.

The current portion of income tax expense was $2.4 million for 2008 compared to $0.6 million in 2007. We reported a net operating loss in our 2007 income tax return, and we anticipate reporting a net operating loss in our 2008 income tax return, mainly due to intangible drilling deductions allowed.

Table of Contents

Net Income. Net income increased from $130.6 million for 2007 to $252.1 million for 2008. The primary reasons for this increase include a 19% increase in equivalent volumes sold, a 26% increase in oil prices (net of hedging) and a 24% increase in natural gas prices (net of hedging) between periods, amortization of deferred gain on sale, lower interest expense and gains on mark-to-market derivatives. These positive factors were partially offset by higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative expenses, Production Participation Plan expense and income taxes, as well as no gain on sale of properties during 2008.

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

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $35.9 million to $809.0 million in 2007 compared to 2006. Sales are a function of volumes sold and average sales prices. Our oil sales volumes decreased 2% between periods, while our natural gas sales volumes decreased 4%. The volume declines resulted in part from property sales, production shut-ins due to delays at third-party refineries, and normal field production decline, which factors were partially offset by production increases from development activities. Our 2007 and 2006 property divestitures resulted in a decline of approximately 317 MBOE, 48% of which related to natural gas. Approximately 34 MBOE of production from the Postle field was shut-in or restricted from February 19 through March 8, 2007 due to a fire at a third-party refinery, and approximately 32 MBOE of production from the Boies Ranch field was restricted from July 28 to November 18, 2007 due to repairs at the field's gas processing plant. During 2007, we also converted several production wells to injectors at our North Ward Estes field, as the Phase I area of the reservoir was pressured up in preparation for CO2 injection. Our average price for oil before effects of hedging increased 13% between periods, and our average price for natural gas before effects of hedging decreased 6%.

Loss on Oil and Natural Gas Hedging Activities. We hedged 53% of our oil volumes during 2007, incurring cash settlement losses of $21.2 million, and 54% of our oil volumes during 2006, incurring cash settlement losses of $9.4 million. We hedged 16% of our gas volumes during 2007, incurring no cash settlement gains or losses, and 59% of our gas volumes during 2006, resulting in cash settlement gains of $1.9 million.

Gain on Sale of Properties. During 2007, we sold certain non-core properties for aggregate sales proceeds of $52.6 million, resulting in a pre-tax gain on sale of $29.7 million. During 2006, we sold our interests in several non-core properties for an aggregate amount of $24.4 million in cash and recognized a pre-tax gain on sale of $12.1 million.

Lease Operating Expenses. Our lease operating expenses for 2007 were $208.9 million, a $25.2 million or 14% increase over 2006. Our lease operating expenses per BOE increased from $12.12 during 2006 to $14.20 during 2007. The increase of 17% on a BOE basis was primarily caused by a high level of workover activity, inflation in the cost of oil field goods and services, and a change in labor billing practices. Workovers amounted to $17.4 million in 2007, as compared to $8.9 million of workover activity during 2006. The cost of oil field goods and services increased due to a higher demand in the industry. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to Council of Petroleum Accountants Societies ("COPAS") guidelines. This change in labor billing practices resulted in lower net general and administrative expense and higher amounts of lease operating expense being charged to us and our joint interest owners on properties we operate.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for 2007 and 2006 were 6.5% and 6.1%, respectively, of oil and natural gas sales. Our production tax rate for 2007 was greater than the rate for 2006 due to the change in property mix associated with recent divestitures in low tax rate jurisdictions and drilling successes in higher tax rate jurisdictions.

Table of Contents

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $30.0 million as compared to 2006. The components of DD&A expense were as follows (in thousands):

	Year Ended December 31, 2007	2006
Depletion	$ 186,838	$ 157,868
Depreciation	3,123	2,675
Accretion of asset retirement obligations	2,850	2,288
Total	$ 192,811	$ 162,831

DD&A increased $30.0 million primarily due to $29.0 million in higher depletion expense between periods. Of this $29.0 million increase in depletion, $33.7 million relates to our higher depletion rate in 2007, which was partially offset by $4.7 million related to lower oil and gas volumes produced during 2007. On a BOE basis, our DD&A rate increased from $10.74 during 2006 to $13.11 for 2007. The primary factors causing this rate increase were (i) $529.3 million in drilling expenditures incurred during the past twelve months in relation to net oil and natural gas reserve additions over the same time period, and (ii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

Exploration and Impairment Costs. Our exploration and impairment costs increased $2.8 million, as compared to 2006. The components of exploration and impairment costs were as follows (in thousands):

	Year Ended December 31, 2007	2006
Exploration	$ 27,344	$ 30,079
Impairment	9,979	4,455
Total	$ 37,323	$ 34,534

During 2007, we participated in a non-operated exploratory well drilled in the Gulf Coast region that resulted in an insignificant amount of dry hole expense. In 2006, we drilled three exploratory dry holes in the Rocky Mountains region, one exploratory dry hole in the Gulf Coast region and one exploratory dry hole in the Mid-Continent region, totaling $7.2 million. This reduction in exploratory dry hole expense was partially offset by an increase in geological and geophysical ("G&G") activity during 2007. G&G costs amounted to $15.7 million during 2007, as compared to $12.2 million in 2006. Impairment charges in 2007 and 2006 relate to the amortization of leasehold costs associated with individually insignificant unproved properties. As of December 31, 2007, the amount of unproved properties being amortized totaled $51.5 million, as compared to $16.2 million as of December 31, 2006.

General and Administrative Expenses. We report general and administrative expenses net of third party reimbursements and internal allocations. The components of general and administrative expenses were as follows (in thousands):

	Year Ended December 31, 2007	2006
General and administrative expenses	$ 72,008	$ 60,972
Reimbursements and allocations	(32,962)	(23,164)
General and administrative expenses, net	$ 39,046	$ 37,808

Table of Contents

General and administrative expenses before reimbursements and allocations increased $11.0 million to $72.0 million during 2007. The largest components of the increase related to (i) $7.5 million of additional salaries and wages for personnel hired during the past twelve months and (ii) $2.9 million in incremental distributions under our Production Participation Plan, attributable primarily to the Company's 2007 oil and gas property divestitures. The increase in reimbursements and allocations in 2007 was caused by increased salary expenses and a higher number of field workers on operated properties. In addition during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. These changes in labor billing practices resulted in higher reimbursements and allocations and, therefore, higher amounts of lease operating expense being allocated to us and charged to our joint interest owners on properties we operate. Our net general and administrative expenses as a percentage of oil and natural gas sales remained constant at 5% for both 2007 and 2006.

Interest Expense. The components of interest expense were as follows (in thousands):

	Year Ended December 31, 2007	Year Ended December 31, 2006
Senior Subordinated Notes	$ 44,691	$ 44,530
Credit Agreement	24,428	21,478
Amortization of debt issue costs and debt discount	5,022	5,208
Accretion of tax sharing liability	1,505	2,016
Other	522	813
Capitalized interest	(3,664)	(556)
Total interest expense	$ 72,504	$ 73,489

The decrease in interest expense was mainly due to increased capitalized interest on the construction and expansion of processing facilities. This decrease was partially offset by increased interest expense on our credit agreement as a result of additional borrowings outstanding in 2007, as well as higher weighted average interest rates on our debt during 2007.

Our weighted average debt outstanding during 2007 was $964.4 million, while it was $945.3 million during 2006. Our weighted average effective cash interest rate was 7.2% during 2007 compared to 7.0% during 2006. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 7.7% during 2007 compared to 7.5% during 2006.

Change in Production Participation Plan Liability. For the year ended December 31, 2007, this non-cash expense was $8.6 million, an increase of $2.4 million as compared to 2007. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2008 under our Production Participation Plan ("Plan"). Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan's five-year vesting period. This expense in 2007 and 2006 primarily reflects (i) changes to future cash flow estimates stemming from a sustained higher commodity price environment, (ii) 2007 drilling activity and (iii) employees' continued vesting in the Plan. For the year ended December 31, 2007, the five-year average historical NYMEX prices used to estimate this liability increased $8.58 for crude oil and $0.67 for natural gas, as compared to increases of $7.40 for crude oil and $0.52 for natural gas for the year ended December 31, 2006. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

Income Tax Expense. Income tax expense totaled $76.6 million in 2007 and $76.9 million for 2006. Our effective income tax rate increased from 33.0% for 2006 to 37.0% for 2007. Our effective income tax rate was higher for 2007 primarily due to several non-recurring benefits recognized in 2006 consisting of: a $4.3 million deferred tax benefit for 2005 enhanced oil recovery ("EOR") tax credits; a $2.3 million benefit relating to a true-up of our effective tax rate to our 2005 state returns as filed; and deferred tax benefits of $1.2 million as a result of state tax legislation enacted in 2006. In addition, we incurred incremental income tax of $1.5 million during 2007 relating to an adjustment of prior year's tax expense upon filing our 2006 returns. This expense was partially offset by a $0.6 million net deferred tax benefit recognized in 2007 for EOR credits relating to 2003 and 2004.

Table of Contents

EOR credits are a credit against federal income taxes for certain costs related to extracting high-cost oil, utilizing certain prescribed "enhanced" tertiary recovery methods. Federal EOR credits are subject to phase-out according to the level of average domestic crude prices. Due to high oil prices during 2007 and 2006, the EOR credit was phased-out in those years.

The current portion of income tax expense was $0.6 million for 2007 compared to $12.3 million in 2006. We reported a net operating loss in our 2007 returns, mainly due to intangible drilling deductions allowed.

Net Income. Net income decreased from $156.4 million in 2006 to $130.6 million for 2007. The primary reasons for this decrease include a 3% decrease in equivalent volumes sold, a 7% decrease in natural gas prices (net of hedging) between periods, higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative expenses, and change in Production Participation Plan liability. The decreased production and natural gas prices and increased expenses were partially offset by an 11% increase in oil prices (net of hedging) between periods, a higher gain on sale of properties, and lower interest expense and income taxes in 2007.

Liquidity and Capital Resources

Overview. At December 31, 2008, our debt to total capitalization ratio was 40.7%, we had $9.6 million of cash on hand and $1,808.8 million of stockholders' equity. At December 31, 2007, our debt to total capitalization ratio was 36.8%, we had $14.8 million of cash on hand and $1,490.8 million of stockholders' equity. In 2008, we generated $763.0 million of cash provided by operating activities, an increase of $369.0 million over 2007. Cash provided by operating activities increased primarily because of higher oil volumes produced in 2008 and higher average sales prices (net of hedging) for both crude oil and natural gas. We also generated $366.8 million from financing activities primarily consisting of net borrowings against our credit agreement. Cash flows from operating and financing activities, as well as $193.7 million in net proceeds from the sale of Trust units, were used to finance $892.1 million of drilling and development expenditures paid in 2008 and $438.8 million of cash acquisition capital expenditures. The following chart details our exploration and development expenditures incurred by region during 2008 (in thousands):

	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 482,916	$ 9,901	$ 492,817	52%
Permian Basin	279,236	10,729	289,965	31%
Mid-Continent	94,331	1,984	96,315	10%
Gulf Coast	43,002	537	43,539	4%
Michigan	18,581	6,151	24,732	3%
Total incurred	918,066	29,302	947,368	100%
Increase in accrued capital expenditures	(25,972)	-	(25,972)	
Total paid	892,094	29,302	$ 921,396	

48

We continually evaluate our capital needs and compare them to our capital resources. 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 significant decrease from the $947.4 million incurred on exploration and development expenditures during 2008. This reduced capital budget is in response to significantly lower oil and natural gas prices experienced during the fourth quarter of 2008 and continuing into 2009. Although we have no specific budget for property acquisitions in 2009, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should attractive acquisition opportunities arise or exploration and development expenditures exceed $474.0 million, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, or agreements with industry partners. Our level of exploration and development expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future.

Credit Agreement. Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), our wholly-owned subsidiary, has a $1.2 billion credit agreement with a syndicate of banks that, as of December 31, 2008, had a borrowing base of $900.0 million with $277.2 million of available borrowing capacity, which is net of $620.0 million in borrowings and $2.8 million in letters of credit outstanding. The borrowing base under the credit agreement is determined at the discretion of our lenders, based on the collateral value of our proved reserves that have been mortgaged to our 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.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas may, throughout the term of the credit agreement, borrow, repay and re-borrow up to the borrowing base in effect at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours in an aggregate amount not to exceed $50.0 million. As of December 31, 2008, $47.2 million was available for additional letters of credit under the agreement.

Interest accrues at our option at either (i) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (ii) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage and are included as a component of interest expense. At December 31, 2008, the effective interest rate on the outstanding principal balance under the credit agreement was 2.5%.

The credit agreement contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders. The credit agreement requires us to maintain a debt to EBITDAX ratio (as defined in the agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit facility) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and our wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions, principal payments on senior notes or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. We were in compliance with our covenants under the credit agreement as of

December 31, 2008. However, a substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants in the future. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for the guarantee, and Equity Oil Company has mortgaged all of its properties, that are included in the borrowing base for the credit agreement, as security for its guarantee.

Table of Contents

We have initiated the process of renewing early this credit agreement held with a syndicate of banks. While we believe that the process will result in the successful renewal of our credit facility, we can provide no assurances that this process will be successfully completed or that such renewal will be completed on terms which are better than or equal to the current terms of our existing credit agreement.

Senior Subordinated Notes. In October 2005, we issued at par $250.0 million of 7% Senior Subordinated Notes due 2014. In April 2005, we issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These 7.25% notes were issued at 98.507% of par, and the associated discount is being amortized to interest expense over the term of these notes. In May 2004, we issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These 7.25% notes were issued at 99.26% of par, and the associated discount is likewise being amortized to interest expense over the term of these notes.

The notes are unsecured obligations of ours and are subordinated to all of our senior debt, which currently consists of Whiting Oil and Gas' credit agreement. The indentures governing the 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 Corporation's credit agreement. Additionally, the indentures governing the notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of December 31, 2008. However, a substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants in the future. Our wholly-owned operating subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company, have fully, unconditionally, jointly and severally guaranteed our obligations under the notes.

Shelf Registration Statement. We have on file with the SEC a universal shelf registration statement to allow us to offer an indeterminate amount of securities in the future. Under the registration statement, we may periodically offer from time to time debt securities, common stock, preferred stock, warrants and other securities or any combination of such securities in amounts, prices and on terms announced when and if the securities are offered. However, we recognize that the issuance of additional securities in periods of market volatility may be less likely. The specifics of any future offerings, along with the use of proceeds of any securities offered, will be described in detail in a prospectus supplement at the time of any such offering.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liabilities since we cannot determine with accuracy the timing or amounts of future payments. The following table summarizes our obligations and commitments as of December 31, 2008 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

Table of Contents

		Payments due by period			
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a)	$ 1,240,000	$ -	$ 620,000	$ 370,000	$ 250,000
Cash interest expense on debt (b)	229,471	58,285	96,317	60,285	14,584
Asset retirement obligations (c)	54,348	6,456	2,363	4,928	40,601
Tax sharing liability (d)	23,687	2,112	3,787	3,261	14,527
Derivative contract liability fair value (e)	45,485	17,354	18,510	9,621	-
Purchase obligations (f)	151,135	25,882	64,493	52,878	7,882
Drilling rig contracts (g)	131,844	55,802	64,748	11,294	-
Operating leases (h)	13,893	2,520	6,060	5,313	-
Total	$ 1,889,863	$ 168,411	$ 876,278	$ 517,580	$ 327,594

(a) Long-term debt consists of the 7.25% Senior Subordinated Notes due 2012 and 2013, the 7% Senior Subordinated Notes due 2014 and the outstanding debt under our credit agreement, and assumes no principal repayment until the due date of the instruments.

(b) Cash interest expense on the 7.25% Senior Subordinated Notes due 2012 and 2013 and the 7% Senior Subordinated Notes due 2014 is estimated assuming no principal repayment until the due date of the instruments. The interest rate swap on the $75.0 million of our $150.0 million fixed rate 7.25% Senior Subordinated Notes due 2012 is assumed to equal 5.6% until the due date of the instrument. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the instrument due date and is estimated at a fixed interest rate of 2.5%.

(c) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related facilities.

(d) Amounts shown represent the present value of estimated payments due to Alliant Energy based on projected future income tax benefits attributable to an increase in our tax bases. As a result of the Tax Separation and Indemnification Agreement signed with Alliant Energy, the increased tax bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax basis for the years ending on or prior to December 31, 2013. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years.

(e) We have entered into derivative contracts primarily in the form of costless collars to hedge our exposure to crude oil and natural gas price fluctuations. With respect to open derivative contracts at December 31, 2008 with certain counterparties, the forward price curves for crude oil and natural gas generally exceeded the price curves that were in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market and commodity price risk.

(f)

We have two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement expiring in December 2014, whereby we have committed to buy certain volumes of CO_2, for use in enhanced recovery projects in our Postle field in Oklahoma and our North Ward Estes field in Texas. The purchase agreements are with different suppliers. Under the terms of the agreements, we are obligated to purchase a minimum daily volume of CO_2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. The CO_2 volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, we expect to avoid any payments for deficiencies.

(g) We currently have nine drilling rigs under long-term contract, of which four drilling rigs expire in 2009, two in 2010, one in 2011, and two in 2012. We also have one workover rig under contract until 2009. All of these rigs are operating in the Rocky Mountains region. As of December 31, 2008, early termination of these contracts would have required maximum penalties of $90.5 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the drilling time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

Table of Contents

(h) We lease 107,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, and an additional 46,700 square feet of office space in Midland, Texas expiring in 2012.

Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

New Accounting Pronouncements

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. We are currently assessing the impact that the adoption will have on our disclosures, operating results, financial position and cash flows.

In March 2008, the FASB issued Statement No. 161, Disclosure about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133 (“SFAS 161”). The adoption of SFAS 161 is not expected to have an impact on our consolidated financial statements, other than additional disclosures. SFAS 161 expands interim and annual disclosures about derivative and hedging activities that are intended to better convey the purpose of derivative use and the risks managed. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51 (“SFAS 160”). As we currently do not have any minority interests, we do not expect the adoption of SFAS 160 to have an impact on our consolidated financial statements. This statement amends ARB No. 51 and intends to improve the relevance, comparability, and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards of the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. SFAS 160 is effective for fiscal years, and interim periods, beginning on or after December 15, 2008.

In December 2007, the FASB issued Statement No. 141R, Business Combinations (“SFAS 141R”). SFAS 141R may have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions we consummate after the effective date. SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in business combinations and determines what information to disclose to enable users of the financial statement to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note 1 to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Table of Contents

Successful Efforts Accounting. We account for our oil and gas operations using the successful efforts method of accounting. Under this method, all costs associated with property acquisitions, successful exploratory wells and all development wells are capitalized. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and gas production costs. All of our properties are located within the continental United States and the Gulf of Mexico.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties, asset retirement obligations, and our long-term Production Participation Plan liability. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and FASB. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

Our proved reserve information included in this report is based on estimates prepared by our independent petroleum engineers, Cawley, Gillespie & Associates, Inc. The independent petroleum engineers evaluated 100% of our estimated proved reserve quantities and their related future net cash flows as of December 31, 2008. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates, impairment calculations, asset retirement obligations and our Production Participation Plan liability in the same period that changes to reserve estimates are made.

Depreciation, Depletion and Amortization. Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties. We review the value of our oil and gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments of producing properties are determined by comparing future net undiscounted cash flows to the net book value at the end of each period. If the net capitalized cost exceeds undiscounted future cash flows, the cost of the property is written down to “fair value,” which is determined using net discounted future cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. We provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred. Individually insignificant unproved properties are amortized on a composite basis, based on past success, experience and average lease-term lives.

Asset Retirement Obligation. Our asset retirement obligations (“AROs”) consist primarily of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas field.

Production Participation Plan. We have a Production Participation Plan (“Plan”) in which all employees participate. Each year, a deemed economic interest in all oil and gas properties acquired or developed during the year is contributed to the Plan. The Compensation Committee of the Board of Directors, in its discretion for each Plan year, allocates a percentage of future net income (defined as gross revenues less production taxes, royalties and direct lease operating expenses) attributable to such properties to Plan participants. Once contributed and allocated, the interests (not legally conveyed) are fixed for each Plan year. The short-term obligation related to the Production Participation Plan is included in the “Accrued Employee Compensation and Benefits” line item in our consolidated balance sheets. This obligation is based on cash flows during the year and is paid annually in cash after year end. The calculation of this liability depends in part on our estimates of accrued revenues and costs as of the end of each reporting period as discussed below under “Revenue Recognition”. The vested long-term obligation related to the Production Participation Plan is the “Production Participation Plan liability” line item in the consolidated balance sheets. This liability is derived primarily from reserve report estimates discounted at 12%, which as discussed above, are subject to revision as more information becomes available. Our price assumptions are currently determined using average prices for the preceding three years. Variances between estimates used to calculate liabilities related to the Production Participation Plan and actual sales, costs and reserve data are integrated into the liability calculations in the period identified. A 10% increase to the pricing assumptions used in the measurement of this liability at December 31, 2008 would have decreased net income before taxes by $9.7 million in 2008.

Derivative Instruments and Hedging Activity. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We use hedging to help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. We primarily utilize costless collars, which are generally placed with major financial institutions. The oil and natural gas reference prices of these commodity derivative contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices we receive. All derivative instruments are recorded on the consolidated balance sheet at fair value. Changes in the derivatives’ fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the fair value gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective and is reclassified to gain (loss) on oil and natural gas hedging activities line item in our consolidated statements of income in the period that the hedged production is delivered. Hedge effectiveness is measured at least quarterly based on the relative changes in the fair value between the derivative contract and the hedged item over time.

Table of Contents

We value our costless collars using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. The discount rate used in the fair values of these instruments includes a measure of nonperformance risk by the counterparty or us, as appropriate. We utilize the counterparties' valuations to assess the reasonableness of our valuations. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Our results of operations each period can be impacted by our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control. If our derivative contracts would not qualify for cash flow hedge treatment, then our consolidated statements of income could include large non-cash fluctuations, particularly in volatile pricing environments, as our contracts are marked to their period end market values.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

Income Taxes and Uncertain Tax Positions. We provide for income taxes in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). In July 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes — An Interpretation of FASB Statement No. 109 ("FIN 48"), which requires income tax positions to meet a more-likely-than-not recognition threshold to be recognized in the financial statements. Under FIN 48, tax positions that previously failed to meet the more-likely-than-not threshold should be recognized in the first subsequent financial reporting period in which that threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not threshold should be derecognized in the first subsequent financial reporting period in which that threshold is no longer met. Prior to 2007 we recorded contingent income tax liabilities to the extent they were probable and could be reasonably estimated. We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Revenue Recognition. We predominantly derive our revenue from the sale of produced oil and gas. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. However, differences have been insignificant.

Accounting for Business Combinations. Our business has grown substantially through acquisitions, and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations to date using the purchase method, which is the only method permitted under SFAS No. 141, Business Combinations, and involves the use of significant judgment.

Table of Contents

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities, and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Each of the business combinations completed during the prior three years consisted of oil and gas properties. The consideration we have paid to acquire these properties or companies was entirely allocated to the fair value of the assets acquired and liabilities assumed at the time of acquisition. Consequently, there was no goodwill recognized from any of our business combinations.

Effects of Inflation and Pricing

We experienced increased costs during 2008, 2007 and 2006 due to increased demand for oil field products and services. The oil and gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

This report contains statements that we believe to be “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe” or “sho the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

Table of Contents

These risks and uncertainties include, but are not limited to: declines in oil or natural gas prices; impacts of the global financial crisis; our level of success in exploitation, exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures, including our ability to obtain drilling rigs and CO2; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; risks related to our level of indebtedness and periodic redeterminations of Whiting Oil and Gas Corporation's borrowing base under our credit agreement; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations and acquisitions; our ability to identify and complete acquisitions, and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete potential asset dispositions; failure of our properties to yield oil or gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption "Risk Factors" in this Annual Report on Form 10-K. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

Table of Contents

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on 2008 production, our income before income taxes for 2008 would have moved up or down $12.4 million for each $1.00 change in oil prices and $3.0 million for every $0.10 change in natural gas prices.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars, although we evaluate other forms of derivative instruments as well. Our derivative contracts have historically qualified for cash flow hedge accounting, whereby accounting rules allow the aggregate change in fair market value to be recorded as accumulated other comprehensive income (loss). Recognition of derivative settlement gains and losses in the consolidated statements of income occurs in the period that hedged production volumes are sold.

Our outstanding hedges as of January 1, 2009 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	01/2009 to 03/2009	544,000	$50.74/$62.55
Crude Oil	04/2009 to 06/2009	518,000	$55.12/$65.68
Crude Oil	07/2009 to 09/2009	496,000	$57.12/$69.55
Crude Oil	10/2009 to 12/2009	478,000	$61.04/$74.89
Crude Oil	01/2010 to 03/2010	430,000	$60.27/$74.81
Crude Oil	04/2010 to 06/2010	415,000	$62.69/$80.09
Crude Oil	07/2010 to 09/2010	405,000	$60.28/$76.98
Crude Oil	10/2010 to 12/2010	390,000	$60.29/$78.23
Crude Oil	01/2011 to 03/2011	360,000	$60.32/$80.33
Crude Oil	04/2011 to 06/2011	360,000	$60.32/$80.33
Crude Oil	07/2011 to 09/2011	360,000	$60.32/$80.33

Crude Oil	10/2011 to 12/2011	360,000	$60.32/$80.33
Crude Oil	01/2012 to 03/2012	330,000	$60.35/$81.70
Crude Oil	04/2012 to 06/2012	330,000	$60.35/$81.70
Crude Oil	07/2012 to 09/2012	330,000	$60.35/$81.70
Crude Oil	10/2012 to 12/2012	330,000	$60.35/$81.70
Crude Oil	01/2013 to 03/2013	290,000	$60.40/$81.66
Crude Oil	04/2013 to 06/2013	290,000	$60.40/$81.66
Crude Oil	07/2013 to 09/2013	290,000	$60.40/$81.66
Crude Oil	10/2013	290,000	$60.40/$81.66
Crude Oil	11/2013	190,000	$59.29/$78.43

Table of Contents

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (as further explained above in the note on Acquisitions and Divestitures), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 2,009 MBbls of crude oil and 7,825 MMcf of natural gas from 2009 through 2012, have been conveyed to the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the Trust, we retain 10% of the net proceeds from the underlying properties. Our retention of 10% of these net proceeds combined with our ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, while we retain 24.2%, of future economic results of such hedges. No additional hedges are allowed to be placed on Trust assets.

The table below summarizes all of the costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Whiting USA Trust I (of which we retain 24.2% of the future economic results and third-party public holders of Trust units receive 75.8% of the future economic results):

Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	01/2009 to 03/2009	50,118	$76.00/$135.85
Crude Oil	04/2009 to 06/2009	48,794	$76.00/$137.55
Crude Oil	07/2009 to 09/2009	47,510	$76.00/$136.41
Crude Oil	10/2009 to 12/2009	46,240	$76.00/$135.72
Crude Oil	01/2010 to 03/2010	45,084	$76.00/$135.09
Crude Oil	04/2010 to 06/2010	43,978	$76.00/$134.85
Crude Oil	07/2010 to 09/2010	42,966	$76.00/$134.89
Crude Oil	10/2010 to 12/2010	41,924	$76.00/$135.11
Crude Oil	01/2011 to 03/2011	40,978	$74.00/$139.68
Crude Oil	04/2011 to 06/2011	40,066	$74.00/$140.08
Crude Oil	07/2011 to 09/2011	39,170	$74.00/$140.15
Crude Oil	10/2011 to 12/2011	38,242	$74.00/$140.75
Crude Oil	01/2012 to 03/2012	37,412	$74.00/$141.27
Crude Oil	04/2012 to 06/2012	36,572	$74.00/$141.73
Crude Oil	07/2012 to 09/2012	35,742	$74.00/$141.70
Crude Oil		35,028	$74.00/$142.21

	10/2012 to 12/2012		
Natural Gas	01/2009 to 03/2009	216,333	$7.00/$22.50
Natural Gas	04/2009 to 06/2009	201,263	$6.00/$14.85
Natural Gas	07/2009 to 09/2009	192,870	$6.00/$15.60
Natural Gas	10/2009 to 12/2009	185,430	$7.00/$14.85
Natural Gas	01/2010 to 03/2010	178,903	$7.00/$18.65
Natural Gas	04/2010 to 06/2010	172,873	$6.00/$13.20
Natural Gas	07/2010 to 09/2010	167,583	$6.00/$14.00
Natural Gas	10/2010 to 12/2010	162,997	$7.00/$14.20
Natural Gas	01/2011 to 03/2011	157,600	$7.00/$17.40
Natural Gas	04/2011 to 06/2011	152,703	$6.00/$13.05
Natural Gas	07/2011 to 09/2011	148,163	$6.00/$13.65
Natural Gas	10/2011 to 12/2011	142,787	$7.00/$14.25
Natural Gas	01/2012 to 03/2012	137,940	$7.00/$15.55
Natural Gas	04/2012 to 06/2012	134,203	$6.00/$13.60
Natural Gas	07/2012 to 09/2012	130,173	$6.00/$14.45
Natural Gas	10/2012 to 12/2012	126,613	$7.00/$13.40

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the 2009 crude oil contracts listed in both tables above, a hypothetical $1.00 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in our gain (loss) on hedging activities in 2009 of $6.2 million. For the 2009 natural gas contracts listed above, a hypothetical $0.10 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in our gain (loss) on hedging activities in 2009 of $0.06 million.

Table of Contents

In a 1997 acquisition of non-operated properties, we became subject to the operator's fixed price gas sales contract with end users for a portion of the natural gas we produce in Michigan. This contract has built-in pricing escalators of 4% per year. Our estimated future production volumes to be sold under the fixed pricing terms of this contract as of January 1, 2009 are summarized below:

Commodity	Period Remaining	Monthly Volume (MMbtu)	2009 Price Per MMbtu
Natural Gas	01/2009 to 05/2011	23,000	$ 5.14
Natural Gas	01/2009 to 09/2012	67,000	$ 4.56

Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit agreement. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to six months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate Senior Subordinated Notes. At December 31, 2008, our outstanding principal balance under our credit agreement was $620.0 million and the weighted average interest rate on the outstanding principal balance was 2.5%. At December 31, 2008, the carrying amount approximated fair market value. Assuming a constant debt level of $620.0 million, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $5.9 million.

Interest Rate Swap

In August 2004, we entered into an interest rate swap contract to hedge the fair value of $75.0 million of our 7.25% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that we receive the fixed rate of 7.25% and pay the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus our margin of 2.345% is less than 7.25%, we receive a payment from the counterparty equal to the difference in rate times $75.0 million for the six month period. When LIBOR plus our margin of 2.345% is greater than 7.25%, we pay the counterparty an amount equal to the difference in rate times $75.0 million for the six month period. The LIBOR rate as of the November 1, 2008 swap reset date was 3.3%. As of December 31, 2008, we have recorded a long term asset of $1.7 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding increase in the carrying value of the Senior Subordinated Notes.

Table of Contents

Item 8. Financial Statements and Supplementary Data

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Whiting Petroleum Corporation and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2008 using the criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management believes that, as of December 31, 2008, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein on the following page.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Whiting Petroleum Corporation:

We have audited the internal control over financial reporting of Whiting Petroleum Corporation and its subsidiaries (the "Company") as of December 31, 2008 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Table of Contents

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2008 of the Company and our report dated February 25, 2009, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 25, 2009

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Whiting Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Whiting Petroleum Corporation and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 25, 2009

Table of Contents

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 9,624	$ 14,778
Accounts receivable trade, net	122,833	110,437
Derivative assets	46,780	-
Deferred income taxes	-	27,720
Deposits on oil field equipment	17,170	-
Prepaid expenses and other	20,667	9,232
Total current assets	217,074	162,167
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	4,423,197	3,313,777
Unproved properties	106,436	55,084
Other property and equipment	91,099	37,778
Total property and equipment	4,620,732	3,406,639
Less accumulated depreciation, depletion and amortization	(886,065)	(646,943)
Total property and equipment, net	3,734,667	2,759,696
DEBT ISSUANCE COSTS	10,779	15,016
DERIVATIVE ASSETS	38,104	-
OTHER LONG-TERM ASSETS	28,457	15,132
TOTAL	$ 4,029,081	$ 2,952,011

See notes to consolidated financial statements. (Continued)

Table of Contents

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)

LIABILITIES AND STOCKHOLDERS' EQUITY	December 31, 2008	December 31, 2007
CURRENT LIABILITIES:		
Accounts payable	$ 64,610	$ 19,280
Accrued capital expenditures	84,960	58,988
Accrued liabilities	45,359	29,551
Accrued interest	9,673	11,240
Oil and gas sales payable	35,106	26,205
Accrued employee compensation and benefits	41,911	21,081
Production taxes payable	20,038	12,936
Deferred gain on sale	14,650	-
Derivative liabilities	17,354	72,796
Deferred income taxes	15,395	-
Tax sharing liability	2,112	2,587
Total current liabilities	351,168	254,664
NON-CURRENT LIABILITIES:		
Long-term debt	1,239,751	868,248
Deferred income taxes	390,902	242,964
Deferred gain on sale	73,216	-
Production Participation Plan liability	66,166	34,042
Asset retirement obligations	47,892	35,883
Tax sharing liability	21,575	23,070
Derivative liabilities	28,131	-
Other long-term liabilities	1,489	2,314
Total non-current liabilities	1,869,122	1,206,521
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $0.001 par value; 75,000,000 shares authorized, 42,582,100 and 42,480,497 shares issued as of December 31, 2008 and 2007, respectively	43	42
Additional paid-in capital	971,310	968,876
Accumulated other comprehensive loss	17,271	(46,116)
Retained earnings	820,167	568,024
Total stockholders' equity	1,808,791	1,490,826
TOTAL	$ 4,029,081	$ 2,952,011

See notes to consolidated financial statements. (Concluded)

Table of Contents

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share data)

	Year Ended December 31, 2008	2007	2006
REVENUES AND OTHER INCOME:			
Oil and natural gas sales	$ 1,316,480	$ 809,017	$ 773,120
Loss on oil and natural gas hedging activities	(107,555)	(21,189)	(7,501)
Gain on sale of properties	-	29,682	12,092
Amortization of deferred gain on sale	12,143	-	-
Interest income and other	1,051	1,208	1,116
Total revenues and other income	1,222,119	818,718	778,827
COSTS AND EXPENSES:			
Lease operating	241,248	208,866	183,642
Production taxes	87,548	52,407	47,095
Depreciation, depletion and amortization	277,448	192,811	162,831
Exploration and impairment	55,257	37,323	34,534
General and administrative	61,684	39,046	37,808
Interest expense	65,078	72,504	73,489
Change in Production Participation Plan liability	32,124	8,599	6,156
Gain on mark-to-market derivatives	(7,088)	-	-
Total costs and expenses	813,299	611,556	545,555
INCOME BEFORE INCOME TAXES	408,820	207,162	233,272
INCOME TAX EXPENSE:			
Current	2,361	550	12,346
Deferred	154,316	76,012	64,562
Total income tax expense	156,677	76,562	76,908
NET INCOME	$ 252,143	$ 130,600	$ 156,364
NET INCOME PER COMMON SHARE, BASIC	$ 5.96	$ 3.31	$ 4.26
NET INCOME PER COMMON SHARE, DILUTED	$ 5.94	$ 3.29	$ 4.25
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	42,310	39,483	36,736
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	42,447	39,645	36,826

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 252,143	$ 130,600	$ 156,364
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	277,448	192,811	162,831
Deferred income taxes	154,316	76,012	64,562
Amortization of debt issuance costs and debt discount	4,801	5,022	5,208
Accretion of tax sharing liability	1,267	1,505	2,016
Stock-based compensation	4,177	5,057	3,969
Gain on sale of properties	-	(29,682)	(12,092)
Amortization of deferred gain on sale	(12,143)	-	-
Undeveloped leasehold and oil and gas property impairments	25,955	9,979	4,455
Change in Production Participation Plan liability	32,124	8,599	6,156
Unrealized gain on mark-to-market derivatives	(6,189)	-	-
Other non-current	(18,825)	(5,086)	2,653
Changes in current assets and liabilities:			
Accounts receivable trade	(12,396)	(12,606)	3,235
Prepaid expenses and other	(29,136)	1,404	(2,268)
Accounts payable and accrued liabilities	55,964	(3,833)	20,412
Accrued interest	(1,567)	2,116	(2,770)
Other current liabilities	35,090	12,134	(3,522)
Net cash provided by operating activities	763,029	394,032	411,209
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash acquisition capital expenditures	(438,759)	(21,568)	(87,562)
Drilling and development capital expenditures	(892,094)	(497,988)	(464,407)
Proceeds from sale of oil and gas properties	1,450	52,585	24,390
Proceeds from sale of marketable securities	764	-	-
Net proceeds from sale of 11,677,500 units in Whiting USA Trust I	193,692	-	-
Net cash used in investing activities	(1,134,947)	(466,971)	(527,579)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common stock	-	210,394	-
Long-term borrowings under credit agreement	1,105,000	384,400	325,000
Repayments of long-term borrowings under credit agreement	(735,000)	(514,400)	(205,000)
Repayments to Alliant Energy Corporation	(3,236)	(3,019)	(3,675)
Debt issuance costs	-	(75)	(253)
Tax effect from restricted stock vesting	-	45	288
Net cash provided by financing activities	366,764	77,345	116,360
	(5,154)	4,406	(10)

NET CHANGE IN CASH AND CASH EQUIVALENTS			
CASH AND CASH EQUIVALENTS:			
Beginning of period	14,778	10,372	10,382
End of period	$ 9,624	$ 14,778	$ 10,372

See notes to consolidated financial statements. (Continued)

Table of Contents

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2008	2007	2006
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for income taxes	$ 1,667	$ 1,446	$ 12,063
Cash paid for interest	$ 60,578	$ 63,861	$ 69,034
NONCASH INVESTING ACTIVITIES:			
Accrued capital expenditures during the year	$ 84,960	$ 58,988	$ 25,742

See notes to consolidated financial statements. (Concluded)

Table of Contents

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(In thousands)

	Common Stock							
	Shares	Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Retained Earnings	Total Stockholders' Equity	Comprehensive Income
BALANCES-January 1, 2006	36,842	37	753,093	(34,620)	(2,031)	281,383	997,862	$ 88,327
Net income	-	-	-	-	-	156,364	156,364	156,364
Change in derivative fair values, net of taxes of $15,409	-	-	-	24,140	-	-	24,140	24,140
Realized loss on settled derivative contracts, net of taxes of $2,923	-	-	-	4,578	-	-	4,578	4,578
Restricted stock issued	126	-	-	-	-	-	-	-
Restricted stock forfeited	(10)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(10)	-	(440)	-	-	-	(440)	-
Tax effect from restricted stock vesting	-	-	288	-	-	-	288	-
Adoption of SFAS 123R	-	-	(2,122)	-	2,031	-	(91)	-
Stock-based compensation	-	-	3,969	-	-	-	3,969	-
BALANCES-December 31, 2006	36,948	37	754,788	(5,902)	-	437,747	1,186,670	$ 185,082
Adoption of FIN 48	-	-	-	-	-	(323)	(323)	-
Net income	-	-	-	-	-	130,600	130,600	130,600
Change in derivative fair values, net of taxes of $31,012	-	-	-	(53,637)	-	-	(53,637)	(53,637)
Realized loss on settled derivative contracts, net of taxes of $7,766	-	-	-	13,423	-	-	13,423	13,423
Issuance of stock, secondary offering	5,425	5	210,389	-	-	-	210,394	-
Restricted stock issued	150	-	-	-	-	-	-	-
Restricted stock forfeited	(12)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(31)	-	(1,403)	-	-	-	(1,403)	-
	-	-	45	-	-	-	45	-

Tax effect from restricted stock vesting								
Stock-based compensation	-	-	5,057	-	-	-	5,057	-
BALANCES-December 31, 2007	42,480	42	968,876	(46,116)	-	568,024	1,490,826	$ 90,386
Net income	-	-	-	-	-	252,143	252,143	252,143
Change in derivative fair values, net of taxes of $1,812	-	-	-	(3,072)	-	-	(3,072)	(3,072)
Realized loss on settled derivative contracts, net of taxes of $39,903	-	-	-	67,652	-	-	67,652	67,652
Ineffectiveness gain on hedging activities, net of taxes of $703	-	-	-	(1,193)	-	-	(1,193)	(1,193)
Restricted stock issued	139	1	-	-	-	-	1	-
Restricted stock forfeited	(7)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(30)	-	(1,743)	-	-	-	(1,743)	-
Stock-based compensation	-	-	4,177	-	-	-	4,177	-
BALANCES-December 31, 2008	42,582	$ 43	$ 971,310	$ 17,271	$ -	$ 820,167	$ 1,808,791	$ 315,530

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company that acquires, exploits, develops and explores for crude oil, natural gas and natural gas liquids primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to “Whiting” or the “Company” are to Whiting Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation of Consolidated Financial Statements—The consolidated financial statements include the accounts of Whiting Petroleum Corporation, its consolidated subsidiaries, all of which are wholly-owned, and Whiting’s pro rata share of the accounts of Whiting USA Trust I pursuant to its 15.8% ownership interest. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company’s equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and natural gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) income taxes; (7) Production Participation Plan and other accrued liabilities; (8) valuation of derivative instruments; and (9) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Cash and Cash Equivalents—Cash equivalents consist of demand deposits and highly liquid investments which have an original maturity of three months or less.

Accounts Receivable Trade—Whiting’s accounts receivable trade consists mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. For receivables from joint interest owners, Whiting typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company’s oil and gas receivables are collected within two months, and to date, the Company has had minimal bad debts.

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectibility. At December 31, 2008 and 2007, the Company had an allowance for doubtful accounts of $0.6 million and $0.3 million, respectively.

Inventories—Materials and supplies inventories consist primarily of tubular goods and production equipment, carried at weighted-average cost. Materials and supplies are included in other property and equipment. Crude oil in tanks inventory is carried at the lower of the estimated cost to produce or market value and is included in prepaid expenses and other.

71

Table of Contents

Oil and Gas Properties

Proved. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and development costs, including the cost of CO2 purchased for injection, are capitalized when incurred and depleted on a unit-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. Costs of drilling exploratory wells are initially capitalized, but are charged to expense if the well is determined to be unsuccessful.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property is written down to "fair value". Fair value for oil and gas properties is generally determined based on discounted future net cash flows. Impairment expense for proved properties is reported in exploration and impairment expense.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized in income.

Interest cost is capitalized as a component of property cost for development projects that require greater than six months to be readied for their intended use. During 2008, 2007 and 2006, the Company capitalized interest of $3.1 million, $3.7 million and $0.6 million, respectively.

Unproved. Unproved properties consist of costs incurred to acquire undeveloped leases as well as costs to acquire unproved reserves. Undeveloped lease costs and unproved reserve acquisition costs are capitalized, and individually insignificant unproved properties are amortized on a composite basis, based on past success, experience and average lease-term lives. The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. Unamortized lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. As unproved reserves are developed and proven, the associated costs are likewise reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense for unproved properties is reported in exploration and impairment expense.

Exploratory. Geological and geophysical costs, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both proved and unproved reserves, those seismic costs are proportionately allocated between development costs and exploration expense.

Costs of drilling exploratory wells are initially capitalized, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs are charged to expense. Cost incurred for exploratory wells that find reserves, which cannot yet be classified as proved, continue to be capitalized if (a) the well has found a sufficient quantity of reserves to justify completion as a producing well, and (b) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if the Company obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well costs, net of any salvage value, are expensed.

72

Table of Contents

Other Property and Equipment. Other property and equipment consists mainly of materials and supplies inventories which are not depreciated. Also included in other property and equipment are an oil pipeline, furniture and fixtures, leasehold improvements and automobiles, which are stated at cost and depreciated using the straight-line method over their estimated useful lives ranging from 4 to 33 years.

Debt Issuance Costs—Debt issuance costs related to the Company's Senior Subordinated Notes are amortized to interest expense using the effective interest method over the term of the related debt. Debt issuance costs related to the credit facility are amortized to interest expense on a straight-line basis over the borrowing term.

Asset Retirement Obligations and Environmental Costs—Asset retirement obligations relate to future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when the asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period through charges to depreciation, depletion and amortization expense, and the capitalized cost is depleted on a units-of-production basis over the proved developed reserves of the related asset. Revisions to estimated retirement obligations result in adjustments to the related capitalized asset and corresponding liability.

Liabilities for environmental costs are recorded on an undiscounted basis when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties.

Derivative Instruments—The Company enters into derivative contracts, primarily costless collars, to manage its exposure to commodity price risk and also enters into derivatives, interest rate swaps, to manage its exposure to interest rate risk. All derivative instruments, other than those that meet the normal purchase and sales exceptions, are recorded on the balance sheet as either an asset or liability measured at fair value. Gains and losses from changes in the fair value of derivative instruments are recognized immediately in earnings, unless the derivative meets specific hedge accounting criteria, and the derivative has been designated as a hedge. Cash flows from derivatives used to manage commodity price risk and interest rate risk are classified in operating activities along with the cash flows of the underlying hedged transactions. The Company does not enter into derivative instruments for speculative or trading purposes.

For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized in accumulated other comprehensive income (loss) and is reclassified to net income when the underlying forecasted transaction occurs. Any ineffective portion of such hedges is recognized in (gain) loss on mark-to-market derivatives as it occurs. The ineffective portion of the hedge, if any, is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. For discontinued cash flow hedges, prospective changes in the fair value of the derivative are recognized in earnings. The accumulated gain or loss recognized in accumulated other comprehensive income (loss) at the time a hedge is discontinued continues to be deferred until the original forecasted transaction occurs. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in accumulated other comprehensive income (loss) is immediately reclassified into earnings.

For derivatives designated as hedges of the fair value of recognized assets, liabilities or firm commitments, changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in earnings the extent to which the hedge is not effective, if any, in achieving offsetting changes in fair value.

Table of Contents

The Company formally documents all relationships between hedging instruments and hedged items, as well as the risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. To designate a derivative as a cash flow hedge, the Company documents at the hedge's inception its assessment as to whether the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. If, during the derivative's term, the Company determines that the hedge is no longer highly effective, hedge accounting is prospectively discontinued.

Deferred Gain on Sale—The deferred gain on sale of 11,677,500 Whiting USA Trust I units is amortized to income based on the units-of-production method.

Revenue Recognition—Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if the collectibility of the revenue is probable. Revenues from the production of gas properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest (entitlement method). Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are reflected as receivables. Gas imbalance receivables or payables are valued at the lowest of (i) the current market price; (ii) the price in effect at the time of production; or (iii) the contract price, if a contract is in hand. As of December 31, 2008 and 2007, the Company was in a net under (over) produced imbalance position of 54,215 Mcf and (102,000) Mcf, respectively.

General and Administrative Expenses—General and administrative expenses are reported net of reimbursements of overhead costs that are allocated to working interest owners in the oil and gas properties operated by Whiting.

Maintenance and Repairs—Maintenance and repair costs which do not extend the useful lives of property and equipment are charged to expense as incurred. Major replacements, renewals and betterments are capitalized.

Income Taxes—Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are accounted for using the liability method. Under this method, deferred tax assets and liabilities are determined by applying the enacted statutory tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the Company's financial statements. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized. The Company's income tax positions must meet a more-likely-than-not recognition threshold to be recognized, and any potential accrued interest and penalties related to unrecognized tax benefits are recognized within income tax expense.

Earnings Per Share—Basic net income per common share is calculated by dividing net income by the weighted average number of common shares outstanding during each year. Diluted net income per common share is calculated by dividing net income by the weighted average number of common shares outstanding and other dilutive securities. The only securities considered dilutive are the Company's unvested restricted stock awards.

Industry Segment and Geographic Information—The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, natural gas and natural gas liquids. The Company considers its gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and substantially all of its revenues are attributable to United States customers.

Table of Contents

Fair Value of Financial Instruments—The Company has included fair value information in these notes when the fair value of our financial instruments is materially different from their book value. Cash and cash equivalents, accounts receivable and payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The Company's credit agreement has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates. The Company's interest rate swap and the related hedged portion of its Senior Subordinated Notes are recorded at fair value, as are derivative financial instruments, which include in the fair market value a measure of the Company's own nonperformance risk or that of its counterparties as appropriate.

Concentration of Credit Risk—Whiting is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. During 2008, sales to Plains Marketing LP and Valero Energy Corporation accounted for 15% and 14%, respectively, of the Company's total oil and gas production revenue. During 2007, sales to Valero Energy Corporation and Plains Marketing LP accounted for 14% and 13%, respectively, of the Company's total oil and gas production revenue. During 2006, sales to Plains Marketing LP and Valero Energy Corporation accounted for 16% and 12%, respectively, of the Company's total oil and gas production revenue. Commodity derivative contracts held by the Company are with four counterparties, all of which are part of Whiting's credit facility and all of which have investment-grade ratings from Moody's and Standard & Poor. As of December 31, 2008, outstanding derivative contracts with JP Morgan represent 73% of total crude oil and natural gas volumes hedged.

New Accounting Pronouncements— On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. We are currently assessing the impact that the adoption will have on our disclosures, operating results, financial position and cash flows.

In March 2008, the FASB issued Statement No. 161, Disclosure about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133 ("SFAS 161"). The adoption of SFAS 161 is not expected to have an impact on the Company's consolidated financial statements, other than additional disclosures. SFAS 161 expands interim and annual disclosures about derivative and hedging activities that are intended to better convey the purpose of derivative use and the risks managed. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51 ("SFAS 160"). The Company does not currently have any minority interests and therefore the adoption of SFAS 160 will not have a material impact on its consolidated financial statements. This statement amends ARB No. 51 and intends to improve the relevance, comparability, and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards of the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. SFAS 160 is effective for fiscal years, and interim periods, beginning on or after December 15, 2008.

Table of Contents

In December 2007, the FASB issued Statement No. 141R, Business Combinations ("SFAS 141R"). SFAS 141R may have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions we consummate after the effective date. SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in business combinations and determines what information to disclose to enable users of the financial statement to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008.

2. ACQUISITIONS AND DIVESTITURES

2008 Acquisition

On May 30, 2008, Whiting 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 unadjusted purchase price of $365.0 million.

This acquisition was recorded using the purchase method of accounting. The table below summarizes the allocation of the $359.4 million adjusted purchase price, based on the acquisition date fair value of the assets acquired and the liabilities assumed (in thousands).

	Flat Rock
Purchase price	$ 359,380
Allocation of purchase price:	
Proved properties	$ 251,895
Unproved properties	79,498
Gas gathering and processing facilities	35,736
Liabilities assumed	(7,749)
Total	$ 359,380

Acquisition Pro Forma—In the Company's consolidated statements of income, Flat Rock's results of operations are included with the Company's results beginning May 31, 2008. The following table, however, reflects the unaudited pro forma results of operations for the twelve months ended December 31, 2008 and 2007, as though the Flat Rock acquisition had occurred on the first day of each period presented. The pro forma information below includes numerous assumptions and is not necessarily indicative of what historical results would have been or what future results of operations will be.

		Pro Forma (Unaudited)	
	Whiting (As reported)	Flat Rock	Consolidated
Twelve months ended December 31, 2008:			
Total revenues	$ 1,222,119	$ 17,761	$ 1,239,880
Net income	252,143	1,144	253,287
Net income per common share – basic	5.96	0.03	5.99

Net income per common share – diluted	5.94	0.03	5.97
Twelve months ended December 31, 2007:			
Total revenues	$ 818,718	$ 24,648	$ 843,366
Net income	130,600	(4,560)	126,040
Net income per common share – basic	3.31	(0.12)	3.19
Net income per common share – diluted	3.29	(0.11)	3.18

Table of Contents

2008 Divestiture

On April 30, 2008, the Company 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. Whiting’s 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. The Company used the net offering proceeds to reduce a portion of the debt outstanding under its 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, Whiting conveyed a term net profits interest in certain of its oil and gas properties to the Trust in exchange for 13,863,889 Trust units. The Company has 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.

2007 Acquisitions

There were no significant acquisitions during the year ended December 31, 2007.

2007 Divestitures

On July 17, 2007, the Company sold its 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.

During 2007, the Company sold its 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. The divested properties are located in Colorado, Louisiana, Michigan, Montana, New Mexico, North Dakota, Oklahoma, Texas and Wyoming.

2006 Acquisitions

Utah Hingeline. On August 29, 2006, Whiting acquired a 15% working interest in approximately 170,000 acres of unproved properties in the central Utah Hingeline play for $25.0 million. No producing properties or proved reserves were associated with this acquisition. As part of the acquisition of this property, the operator agreed to pay 100% of Whiting’s 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. During 2008, based on drilling results, Whiting determined that 1,873 net acres within its Utah Hingeline position would no longer be evaluated, drilled or otherwise developed, and Whiting has therefore recorded a $10.9 million non-cash charge for the partial impairment of this unproved property.

Table of Contents

Michigan Properties. On August 15, 2006, Whiting acquired 65 producing properties, a gathering line, gas processing plant and approximately 30,400 net acres of leasehold held by production in Michigan for an aggregate purchase price of $26.0 million.

The Company funded its 2006 acquisitions with cash on hand as well as through borrowings under its credit agreement.

2006 Divestitures

During 2006, the Company sold its interests in several non-core oil and gas producing properties for an aggregate amount of $24.4 million in cash. The divested properties included interests in the Cessford field in Alberta, Canada; Permian Basin of West Texas and New Mexico; and the Ashley Valley field in Uintah County, Utah. The Company recognized a pre-tax gain on sale of $12.1 million related to these divestitures.

3. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2008 and 2007 (in thousands):

	December 31, 2008	December 31, 2007
Credit agreement	$ 620,000	$ 250,000
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,541 and $1,966, respectively	218,459	218,034
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $397 and $537, respectively	151,292	150,214
Total debt	$ 1,239,751	$ 868,248

Credit Agreement—The Company's wholly-owned subsidiary, Whiting Oil and Gas Corporation ("Whiting Oil and Gas") has a $1.2 billion credit agreement with a syndicate of banks that, as of December 31, 2008, had a borrowing base of $900.0 million with $277.2 million of available borrowing capacity, which is net of $620.0 million in borrowings and $2.8 million in letters of credit outstanding. The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the 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.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas may, throughout the five-year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company in an aggregate amount not to exceed $50.0 million. As of December 31, 2008, $47.2 million was available for additional letters of credit under the agreement.

Table of Contents

Interest accrues at the Company's option at either (i) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (ii) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage, and are included as a component of interest expense. At December 31, 2008, the interest rate on the outstanding principal balance under the credit agreement was 2.5%.

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders. The credit agreement requires the Company to maintain a debt to EBITDAX ratio (as defined in the agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement which includes an add back of the available borrowing capacity under the credit facility) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and Whiting Petroleum Corporation's wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions, principal payments on senior notes, or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. The Company was in compliance with its covenants under the credit agreement as of December 31, 2008. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for its guarantee, and Equity Oil Company has mortgaged all of its properties, that are included in the borrowing base for the credit agreement, as security for its guarantee.

Senior Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due 2014. The estimated fair value of these notes was $175.9 million as of December 31, 2008, based on quoted market prices for these same debt securities.

In April 2005, the Company issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount of $3.3 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.4%. The estimated fair value of these notes was $154.0 million as of December 31, 2008, based on quoted market prices for these same debt securities.

In May 2004, the Company issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount of $1.1 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.3%. The estimated fair value of these notes was $110.4 million as of December 31, 2008, based on quoted market prices for these same debt securities.

The notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of Whiting Oil and Gas' credit agreement. The indentures governing the notes restrict the Company from incurring additional indebtedness, subject to certain exceptions, unless its fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If the Company were in violation of this covenant, then it may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. Additionally, the indentures governing the notes contain various restrictive covenants that are substantially identical and may limit the Company's ability to, among other things, pay cash dividends, redeem or repurchase the Company's capital stock or the Company's subordinated debt, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of the Company's management in certain respects. The Company was in compliance with these covenants as of December 31, 2008. The Company's obligations under the notes are fully, unconditionally, jointly and severally guaranteed by all of the Company's wholly-owned operating subsidiaries, Whiting Oil and Gas, Whiting Programs, Inc. and Equity Oil Company (the "Guarantors"). Any subsidiaries other than the Guarantors are minor subsidiaries as defined by Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in guarantor subsidiaries.

Table of Contents

Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of $75.0 million of its 7.25% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that the Company receives the fixed rate of 7.25% and pays the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus the Company's margin of 2.345% is less than 7.25%, the Company receives a payment from the counterparty equal to the difference in rate times $75.0 million for the six month period. When LIBOR plus the Company's margin of 2.345% is greater than 7.25%, the Company pays the counterparty an amount equal to the difference in rate times $75.0 million for the six month period. The LIBOR rate at December 31, 2008 was 1.75%. For the years ended December 31, 2008, 2007 and 2006, Whiting recognized realized gains (losses) of $0.9 million, $(0.4) million and $(0.2) million, respectively, on the interest rate swap. As of December 31, 2008, the Company has recorded a long-term asset of $1.7 million related to the interest rate swap, which has been designated as a fair value hedge, with an offsetting increase to the fair value of the 7.25% Senior Subordinated Notes due 2012.

4. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California), in accordance with applicable local, state and federal laws. The Company determines asset retirement obligations by calculating the present value of estimated cash flows related to plug and abandonment obligations. The current portions at December 31, 2008 and 2007 were $6.5 million and $1.3 million, respectively, and were recorded in accrued liabilities. The following table provides a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2008 and 2007 (in thousands):

	Year Ended December 31, 2008	2007
Beginning asset retirement obligation	$ 37,192	$ 37,534
Additional liability incurred	3,503	1,490
Revisions in estimated cash flows	16,287	76
Accretion expense	3,236	2,850
Obligations on sold or conveyed properties	(536)	(2,557)
Liabilities settled	(5,334)	(2,201)
Ending asset retirement obligation	$ 54,348	$ 37,192

During 2008, Whiting recognized $16.3 million in revisions to its asset retirement obligations for i) changes in the estimated timing of plug and abandonment cash outflows associated with downward revisions in oil and natural gas reserves related to decreases in oil and natural gas prices, and ii) increases in estimated future obligations associated with higher costs of oil field goods and services.

Table of Contents

5. DERIVATIVE FINANCIAL INSTRUMENTS

Whiting enters into derivative contracts, primarily costless collars, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company has designated a portion of its derivative contracts as cash flow hedges, whose unrealized fair value gains and losses are recorded to other comprehensive income, while the Company's remaining derivative contracts are not designated as hedges, with gains and losses from changes in fair value recognized immediately in earnings. The Company does not enter into derivative instruments for speculative or trading purposes.

At December 31, 2008, accumulated other comprehensive income consisted of $27.5 million ($17.3 million after tax) of unrealized gains, representing the mark-to-market value of the Company's open commodity contracts designated as cash flow hedges as of the balance sheet date. At December 31, 2007, accumulated other comprehensive loss consisted of $72.8 million ($46.1 million after tax) of unrealized losses, representing the mark-to-market value of the Company's open commodity contracts designated as cash flow hedges as of the balance sheet date.

For the years ended December 31, 2008, 2007 and 2006, Whiting recognized realized cash settlement losses of $107.6 million, $21.2 million and $7.5 million, respectively, on commodity derivatives designated as cash flow hedges, and in 2008 the Company recognized a $1.9 million unrealized gain for the ineffective portion of the fair value change in its cash flow hedge derivatives. Such ineffectiveness is recognized as (gain) loss on mark-to-market derivatives in Whiting's consolidated statements of income. Based on the estimated fair value of the Company's derivative contracts designated as cash flow hedges at December 31, 2008, the Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of $16.0 million during the next twelve months. However, actual cash settlement gains and losses recognized may differ materially.

The following table details the Company's costless collar derivatives, including its proportionate share of Trust hedges, as of January 1, 2009.

	Whiting Petroleum Corporation			
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
2009	6,247,873	577,820	$57.57 - $73.95	$6.50 - $17.11
2010	5,046,289	495,390	$62.34 - $83.00	$6.50 - $15.06
2011	4,435,039	436,510	$61.68 - $86.26	$6.50 - $14.62
2012	4,065,091	384,002	$61.70 - $87.63	$6.50 - $14.27
2013	3,090,000	-	$60.33 - $81.46	n/a
Total	22,884,292	1,893,722		

In connection with the Company's conveyance on April 30, 2008 of a term net profits interest to the Trust and related sale of 11,677,500 Trust units to the public (as further explained in the note on Acquisitions and Divestitures), the right to any future hedge payments made or received by Whiting on certain of its derivative contracts have been conveyed to the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties. Whiting's retention of 10% of these net proceeds combined with its ownership of 2,186,389 Trust units results in third-party public holders of Trust units receiving 75.8%, and Whiting retaining 24.2%, of the future economic results of hedge contracts conveyed to the Trust. The relative ownership of the future economic results of such hedge contracts is reflected in the tables below. No additional hedges are allowed to be placed on Trust assets.

Table of Contents

The 24.2% portion of Trust derivative contracts that Whiting has retained the economic rights to (and which are also included in the table above) are as follows:

	Whiting Petroleum Corporation			
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
2009	139,873	577,820	$76.00 - $137.43	$6.50 - $17.11
2010	126,289	495,390	$76.00 - $134.98	$6.50 - $15.06
2011	115,039	436,510	$74.00 - $140.15	$6.50 - $14.62
2012	105,091	384,002	$74.00 - $141.72	$6.50 - $14.27
Total	486,292	1,893,722		

The 75.8% portion of Trust derivative contracts for which Whiting has transferred the economic rights to third-party public holders of Trust units (and which have not been reflected in the above tables) are as follows:

	Third-party Public Holders of Trust Units			
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
2009	438,113	1,809,868	$76.00 - $137.43	$6.50 - $17.11
2010	395,567	1,551,678	$76.00 - $134.98	$6.50 - $15.06
2011	360,329	1,367,249	$74.00 - $140.15	$6.50 - $14.62
2012	329,171	1,202,785	$74.00 - $141.72	$6.50 - $14.27
Total	1,523,180	5,931,580		

With respect to costless collars entered into by Whiting for which the economic benefits and detriments were conveyed to the Trust, the Company has recorded a current derivative asset of $16.6 million, with a corresponding current derivative liability of $12.6 million, and a non-current derivative asset of $24.9 million, with a corresponding non-current derivative liability of $18.9 million.

The Company has also entered into an interest rate swap designated as a fair value hedge as further explained in Long-Term Debt.

6. FAIR VALUE DISCLOSURES

SFAS 157—Effective January 1, 2008, the Company adopted FASB Statement No. 157, Fair Value Measurements ("SFAS 157") for financial assets and financial liabilities measured at fair value on a recurring basis. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements. As defined in

SFAS 157, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date ("exit price"). The implementation of SFAS 157 did not cause a change in the method of calculating fair value of assets or liabilities, with the exception of incorporating a measure of the Company's own nonperformance risk or that of its counterparties as appropriate, which was not material. The primary impact from adoption was additional disclosures.

Table of Contents

The Company elected to implement SFAS 157 with the one-year deferral permitted by FASB Staff Position No. FAS 157-2, Effective Date of FASB Statement No. 157 ("FSP 157-2"), issued February 2008, which defers the effective date of SFAS 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. As it relates to the Company, the deferral applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; impaired oil and gas property assessments; and the initial recognition of asset retirement obligations for which fair value is used.

In October 2008, the FASB issued FASB Staff Position No. FAS 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active ("FSP 157-3"), which clarifies the application of SFAS 157 in an inactive market and provides an example to demonstrate how the fair value of a financial asset is determined when the market for that financial asset is inactive. The adoption of this standard did not have a material impact on the Company's consolidated financial statements. FSP 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued.

Fair Value Hierarchy—SFAS 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The following table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2008, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Level 1	Level 2	Level 3	December 31, 2008
Assets				
Current portion of commodity derivative assets	$ -	$ 46,780	$ -	$ 46,780
Non-current commodity derivative assets	-	38,104	-	38,104
Other long-term assets (1)	-	1,690	-	1,690
Total	$ -	$ 86,574	$ -	$ 86,574
Liabilities				
Current portion of commodity derivative liabilities	$ -	$ 17,354	$ -	$ 17,354

Non-current commodity derivative liabilities	-	28,131	-	28,131
Long-term debt (1)	-	1,690	-	1,690
Total	$ -	$ 47,175	$ -	$ 47,175

(1) Amount represents interest rate swap (see note on Long-Term Debt).

83

Table of Contents

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above:

Commodity Derivative Instruments—Commodity derivative instruments consist primarily of costless collars for crude oil and natural gas. The Company's costless collars are valued using industry-standard modeling techniques that consider the contractual prices for the underlying instruments as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are designated as Level 2 within the valuation hierarchy. The discount rate used in the fair values of these instruments includes a measure of nonperformance risk. The Company utilizes the counterparties' valuations to assess the reasonableness of its valuations.

Interest Rate Swap—The Company's interest rate swap is valued using the counterparty's marked-to-market statement, which is validated using modeling techniques that include market inputs such as publicly available interest rate yield curves, and is designated as Level 2 within the valuation hierarchy.

SFAS 159—In February 2007, the FASB issued Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115 ("SFAS 159"). SFAS 159 expands the use of fair value accounting but does not affect existing standards which require assets or liabilities to be carried at fair value. On January 1, 2008, the Company adopted SFAS 159 and did not elect fair value accounting for any of its eligible items. The adoption of SFAS 159 therefore had no impact on the Company's consolidated financial position, cash flows or results of operations. If the use of fair value is elected (the fair value option), however, any upfront costs and fees related to the item must be recognized in earnings and cannot be deferred, e.g., debt issue costs. The fair value election is irrevocable and generally made on an instrument-by-instrument basis, even if a company has similar instruments that it elects not to measure based on fair value. Subsequent to the adoption of SFAS 159, changes in fair value are recognized in earnings.

7. STOCKHOLDERS' EQUITY

Common Stock Offering—On July 3, 2007, the Company completed a public offering of its common stock under its existing shelf registration statement, selling 5,425,000 shares of common stock at a price of $40.50 per share and providing net proceeds of $210.4 million. The number of shares includes the sale of 425,000 shares pursuant to the exercise of the underwriters' overallotment option. The Company used the net proceeds to repay a portion of the debt outstanding under its credit agreement.

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive Plan, pursuant to which two million shares of the Company's common stock have been reserved for issuance. No employee or officer participant may be granted options for more than 300,000 shares of common stock, stock appreciation rights relating to more than 300,000 shares of common stock, or more than 150,000 shares of restricted stock during any calendar year.

Table of Contents

Restricted stock awards for executive officers, directors and employees generally vest ratably over three years. The Company uses historical data and projections to estimate expected employee behaviors related to restricted stock forfeitures. The expected forfeitures are then included as part of the grant date estimate of compensation cost. For service-based restricted stock awards, the grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date.

In February of 2007, 79,227 restricted shares, that are subject to certain internal performance metrics in addition to the standard three-year service condition, were granted to executive officers. These internal performance conditions must be met in order for the stock awards to vest. It is therefore possible that no shares could vest in one or more of the three-year vesting periods. The Company recognizes compensation expense for awards subject to performance conditions when it becomes probable that these conditions will be achieved. However, any such compensation expense recognized is reversed if vesting does not actually occur.

In February of 2008, 74,542 restricted shares, that are subject to certain vesting criteria related to Whiting's common stock performance relative to the average of a peer group of companies, were also granted to executive officers. For restricted stock subject to such market-based vesting conditions, the grant date fair value of the award is estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated from historical daily volatilities and represents the extent to which the Company's stock price performance, relative to the average stock price performance of the peer group, is expected to fluctuate during each of the three calendar periods of the award's anticipated term ending December 31, 2010. The risk-free rate is based on a three-year U.S. Treasury rate consistent with the three-year vesting period. The key assumptions used in valuing these market-based restricted shares are as follows:

	2008
Number of simulations	100,000
Expected volatility	36.3%
Risk-free rate	2.24%

The total grant date fair value of the market-based restricted stock as determined by the Monte Carlo valuation model is $1.8 million and will be recognized ratably over the three-year vesting period.

For the years ended December 31, 2008, 2007 and 2006, total stock compensation expense recognized for restricted share awards was $4.2 million, $5.1 million and $4.0 million, respectively.

The following table shows a summary of the Company's nonvested restricted stock as of December 31, 2006, 2007 and 2008 as well as activity during the years then ended (share and per share data, not presented in thousands):

	Number of Shares	Weighted Average Grant Date Fair Value
Restricted stock awards nonvested, January 1, 2006	145,763	$ 32.34
Granted	125,999	$ 43.38
Vested	(58,409)	$ 27.81
Forfeited	(10,089)	$ 37.87
Restricted stock awards nonvested, December 31, 2006	203,264	$ 39.33
Granted	150,815	$ 45.24

Vested	(101,985)	$	36.13
Forfeited	(12,438)	$	44.28
Restricted stock awards nonvested, December 31, 2007	239,656	$	44.15
Granted	138,518	$	40.67
Vested	(112,384)	$	43.46
Forfeited	(7,026)	$	50.66
Restricted stock awards nonvested, December 31, 2008	258,764	$	42.41

Table of Contents

As of December 31, 2008, there was $3.2 million of total unrecognized compensation cost related to unvested restricted stock granted under the stock incentive plans. That cost is expected to be recognized over a weighted average period of 2.0 years. For the years ended December 31, 2008, 2007 and 2006, the total fair value of restricted stock vested was $6.6 million, $4.7 million and $2.6 million, respectively.

Rights Agreement—In 2006, the Board of Directors of the Company declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of common stock of the Company payable to the stockholders of record as of March 2, 2006. Each Right entitles the registered holder to purchase from the Company one one-hundredth of a share of Series A Junior Participating Preferred Stock, par value $0.001 per share ("Preferred Shares"), of the Company at a price of $180.00 per one one-hundredth of a Preferred Share, subject to adjustment. If any person becomes a 15% or more stockholder of the Company, then each Right (subject to certain limitations) will entitle its holder to purchase, at the Right's then current exercise price, a number of shares of common stock of the Company or of the acquirer having a market value at the time of twice the Right's per share exercise price. The Company's Board of Directors may redeem the Rights for $0.001 per Right at any time prior to the time when the Rights become exercisable. Unless the Rights are redeemed, exchanged or terminated earlier, they will expire on February 23, 2016.

8. EMPLOYEE BENEFIT PLANS

Production Participation Plan—The Company has a Production Participation Plan (the "Plan") in which all employees participate. On an annual basis, interests in oil and gas properties acquired, developed or sold during the year are allocated to the Plan as determined annually by the Compensation Committee. Once allocated, the interests (not legally conveyed) are fixed. Interest allocations prior to 1995 consisted of 2%-3% overriding royalty interests. Interest allocations since 1995 have been 2%-5% of oil and gas sales less lease operating expenses and production taxes.

Payments of 100% of the year's Plan interests to employees and the vested percentages of former employees in the year's Plan interests are made annually in cash after year-end. Accrued compensation expense under the Plan for the years ended December 31, 2008, 2007 and 2006 amounted to $33.5 million, $15.8 million and $13.2 million, respectively, charged to general and administrative expense and $5.2 million, $2.8 million and $2.5 million, respectively, charged to exploration expense.

Employees vest in the Plan ratably at 20% per year over a five year period. Pursuant to the terms of the Plan, (i) employees who terminate their employment with the Company are entitled to receive their vested allocation of future Plan year payments on an annual basis; (ii) employees will become fully vested at age 62, regardless of when their interests would otherwise vest; and (iii) any forfeitures inure to the benefit of the Company.

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At December 31, 2008, the Company used three-year average historical NYMEX prices of $79.44 for crude oil and $7.64 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control (as defined in the Plan), all employees fully vest, and the Company would distribute to each Plan participant an amount based upon the valuation method set forth in the Plan in a lump sum payment twelve months after the date of termination or within one month after a change in control event. Based on prices at December 31, 2008, if the Company elected to terminate the Plan or if a change of control event occurred, it is estimated that the fully vested lump sum cash payment to employees would approximate $114.6 million. This amount includes $11.4 million attributable to proved undeveloped oil and gas properties and $38.7 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2009. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan.

Table of Contents

The following table presents changes in the estimated long-term liability related to the Plan (in thousands):

	Year Ended December 31, 2008	Year Ended December 31, 2007
Beginning Production Participation Plan liability	$ 34,042	$ 25,443
Change in liability for accretion, vesting and change in estimates	70,811	27,225
Reduction in liability for cash payments accrued and recognized as compensation expense	(38,687)	(18,626)
Ending Production Participation Plan liability	$ 66,166	$ 34,042

The Company records the expense associated with changes in the present value of estimated future payments under the Plan as a separate line item in the consolidated statements of income. The amount recorded is not allocated to general and administrative expense or exploration expense because the adjustment of the liability is associated with the future net cash flows from the oil and gas properties rather than current period performance. The following table presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items (in thousands):

	Year Ended December 31, 2008	2007	2006
General and administrative expense	$ 27,852	$ 7,293	$ 5,196
Exploration expense	4,272	1,306	960
Total	$ 32,124	$ 8,599	$ 6,156

401(k) Plan—The Company has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. The Company's contributions for 2008, 2007 and 2006 were $3.0 million, $2.4 million and $2.1 million, respectively. Employees vest in employer contributions at 20% per year of completed service.

Table of Contents

9. INCOME TAXES

Income tax expense consists of the following (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Current income tax expense:			
Federal	$ -	$ 32	$ 11,576
State	2,361	518	770
Total current income tax expense	2,361	550	12,346
Deferred income tax expense:			
Federal	142,393	72,937	65,402
State	11,923	3,075	(840)
Total deferred income tax expense	154,316	76,012	64,562
Total	$ 156,677	$ 76,562	$ 76,908

Income tax expense differed from amounts that would result from applying the U.S. statutory income tax rate (35%) to income before income taxes as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
U.S. statutory income tax expense	$ 143,087	$ 72,506	$ 81,645
State income taxes, net of federal benefit	13,458	4,176	907
Tax credits	-	330	(4,206)
Statutory depletion	(583)	(405)	(1,245)
Enacted changes in state tax laws	-	(599)	(1,295)
Change in valuation allowance	-	67	1,163
Permanent items	715	570	(187)
Other	-	(83)	126
Total	$ 156,677	$ 76,562	$ 76,908

Table of Contents

The principal components of the Company's deferred income tax assets and liabilities at December 31, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31, 2008	2007
Deferred income tax assets:		
Net operating loss carryforward	$ 124,560	$ 20,952
Derivative instruments	-	26,680
Production Participation Plan liability	24,548	12,581
Tax sharing liability	11,109	10,598
Asset retirement obligations	13,050	11,806
Underwriter fees	6,935	-
Restricted stock compensation	1,979	2,274
Enhanced oil recovery credit carryforwards	7,946	7,946
Alternative minimum tax credit carryforwards	9,653	9,653
State deductibles	2,215	2,135
Foreign tax credit carryforwards	1,230	1,230
Other	655	110
Total deferred income tax assets	203,880	105,965
Less valuation allowances	(1,230)	(1,230)
Net deferred income tax assets	202,650	104,735
Deferred income tax liabilities:		
Oil and gas properties	548,596	319,979
Derivative instruments	12,482	-
Trust distributions	47,869	-
Other	-	-
Total deferred income tax liabilities	608,947	319,979
Total net deferred income tax liabilities	$ 406,297	$ 215,244

As of December 31, 2008, we had federal net operating loss carryforwards of $344.6 million and various state net operating loss carryforwards. The determination of the state net operating loss carryforwards is dependent upon apportionment percentages and state laws that can change from year to year and impact the amount of such carryforwards. If unutilized, the federal net operating loss will expire in 2027 and 2028 and the state net operating loss will expire between 2012 and 2028.

EOR credits are a credit against federal income taxes for certain costs related to extracting high-cost oil, utilizing certain prescribed "enhanced" tertiary recovery methods. As of December 31, 2008, the Company had recognized aggregate enhanced oil recovery credits of $7.9 million that are available to offset regular federal income taxes in the future. These credits can be carried forward and will expire between 2023 and 2025. Federal EOR credits are subject to phase-out according to the level of average domestic crude oil prices. The EOR credit has been phased-out since 2006.

The Company is subject to the alternative minimum tax ("AMT") principally due to accelerated tax depreciation. As of December 31, 2008, the Company had AMT credits totaling $9.7 million that are available to offset future regular federal income taxes. These credits do not expire and can be carried forward indefinitely.

At December 31, 2008, the Company's foreign tax credit carryforwards totaled $1.2 million, which will expire between 2014 and 2016. As of December 31, 2008, a valuation allowance of $1.2 million was established in full for the foreign tax credit carryforwards because the Company determined that it was more likely than not that the benefit from these deferred tax assets will not be realized due to the divestiture of all foreign operations.

Table of Contents

Net deferred income tax liabilities were classified in the consolidated balance sheets as follows (in thousands):

	Year Ended December 31, 2008	2007
Assets:		
Current deferred income taxes	$ -	$ 27,720
Liabilities:		
Current deferred income taxes	15,395	-
Non-current deferred income taxes	390,902	242,964
Net deferred income tax liabilities	$ 406,297	$ 215,244

On January 1, 2007, the Company adopted the provisions of FIN 48, and the following table summarizes the activity related to the Company's liability for unrecognized tax benefits (in thousands):

	Year Ended December 31, 2008	2007
Beginning balance at January 1	$ 170	$ 396
Increases related to tax position taken in the current year	129	96
Decreases associated with accounting method change	-	(322)
Ending balance at December 31	$ 299	$ 170

Included in the unrecognized tax benefit balance at December 31, 2008, are $0.2 million of tax positions, the allowance of which would positively affect the annual effective income tax rate. For the year ended December 31, 2008, the Company did not recognize any interest or penalties with respect to unrecognized tax benefits, nor did the Company have any such interest or penalties previously accrued.

The Company files income tax returns in the U.S. Federal jurisdiction, in various states, and previously filed in two foreign jurisdictions each with varying statutes of limitations. The 2005 through 2008 tax years generally remain subject to examination by federal and state tax authorities. The foreign jurisdictions generally remain subject to examination by their respective authorities for 2002 through 2008.

10. RELATED PARTY TRANSACTIONS

Whiting USA Trust I—As a result of Whiting's retained ownership of 15.8%, or 2,186,389 units in Whiting USA Trust I, the Trust is a related party of the Company. The following table summarizes the related party receivable and payable balances between the Company and the Trust as of December 31, 2008 and 2007 (in thousands):

	December 31, 2008	December 31, 2007
Assets		
Unit distributions due from Trust (1)	$ 1,596	$ -
Total	$ 1,596	$ -
Liabilities		
Unit distributions payable to Trust (2)	$ 10,120	-
Current portion of derivative liability	12,570	-
Non-current derivative liability	18,907	-
Total	$ 41,597	$ -

(1) This amount represents Whiting's 15.8% interest in the net proceeds due from the Trust and is included within Accounts Receivable Trade, Net in the Company's consolidated balance sheets.

(2) This amount represents net proceeds from the Trust's underlying properties as well as realized cash settlements on Trust derivatives, that the Company has received between the last Trust distribution date and December 31, 2008, but which the Company has not yet distributed to the Trust as of December 31, 2008. Due to ongoing processing of Trust revenues and expenses after December 31, 2008, the amount of Whiting's next scheduled distribution to the Trust, and the related distribution by the Trust to its unit holders, will differ from this amount. This amount is included within Accounts Payable in the Company's consolidated balance sheet.

Table of Contents

For the year ended December 31, 2008, Whiting paid $57.8 million, net of state tax withholdings, in unit distributions to the Trust and received $9.0 million in distributions back from the Trust pursuant to its retained ownership in 2,186,389 Trust units.

Tax Sharing Liability—Prior to Whiting's initial public offering in November 2003, it was a wholly-owned indirect subsidiary of Alliant Energy Corporation ("Alliant Energy"), a holding company whose primary businesses are utility companies. When the transactions discussed below were entered into, Alliant Energy was a related party of the Company. As of December 31, 2004 and thereafter, Alliant Energy was no longer a related party.

In connection with Whiting's initial public offering in November 2003, the Company entered into a Tax Separation and Indemnification Agreement with Alliant Energy. Pursuant to this agreement, the Company and Alliant Energy made a tax election with the effect that the tax bases of Whiting's assets were increased to their deemed purchase price immediately prior to such initial public offering. Whiting has adjusted deferred taxes on its balance sheet to reflect the new tax bases of its assets. The additional bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by Whiting.

Under this agreement, the Company has agreed to pay to Alliant Energy 90% of the future tax benefits the Company realizes annually as a result of this step-up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing the Company's actual taxes to the taxes that would have been owed by the Company had the increase in basis not occurred. In 2014, Whiting will be obligated to pay Alliant Energy the present value of the remaining tax benefits, assuming all such tax benefits will be realized in future years. The Company has estimated total payments to Alliant will approximate $34.5 million on an undiscounted basis.

During 2008, 2007 and 2006, the Company made payments of $3.2 million, $3.0 million and $3.7 million, respectively, under this agreement and recognized interest expense of $1.3 million, $1.5 million and $2.0 million, respectively. The Company's estimated payment of $2.1 million to be made in 2009 under this agreement is reflected as a current liability at December 31, 2008.

The Tax Separation and Indemnification Agreement provides that if tax rates were to increase or decrease, the resulting tax benefit or detriment would cause a corresponding adjustment of the tax sharing liability. For purposes of this calculation, management has assumed that no such future changes will occur during the term of this agreement.

Table of Contents

The Company periodically evaluates its estimates and assumptions as to future payments to be made under this agreement. If non-substantial changes (less than 10% on a present value basis) are made to the anticipated payments owed to Alliant Energy, a new effective interest rate is determined for this debt based on the carrying amount of the liability as of the modification date and based on the revised payment schedule. However, if there are substantial changes to the estimated payments owed under this agreement, then a gain or loss is recognized in the consolidated statements of income during the period in which the modification has been made.

Receivable from Alliant Energy—Prior to the Company's initial public offering, the Company was included in the consolidated federal income tax return of Alliant Energy. As a result, current tax due by Whiting was paid to Alliant Energy, and current refunds were received from Alliant. Section 29 tax credits were generated by Whiting in 2002, and the Company therefore had a current receivable from Alliant Energy of $4.1 million for these credits. During 2007, Whiting received payment in full from Alliant, as the Section 29 credits were entirely utilized.

Alliant Energy Guarantee—The Company holds a 6% working interest in three offshore platforms in California and the related onshore plant and equipment. Alliant Energy has guaranteed the Company's obligation in the abandonment of these assets.

11. COMMITMENTS AND CONTINGENCIES

Non-cancelable Leases—The Company leases 107,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through 2013 and an additional 46,700 square feet of office space in Midland, Texas until 2012. Rental expense for 2008, 2007 and 2006 amounted to $2.2 million, $2.1 million and $1.9 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2008 are as follows (in thousands):

2009	$	2,520
2010		2,677
2011		3,383
2012		2,931
2013		2,382
Total	$	13,893

Purchase Contracts— The Company has entered into two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement expiring in December 2014, whereby the Company has committed to buy certain volumes of CO2 for a fixed fee subject to annual escalation. The purchase agreements are with different suppliers, and the CO2 is for use in the Company's enhanced recovery projects in Oklahoma and Texas. Under the terms of the agreements, the Company is obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when delivery was to have occurred. The CO2 volumes planned for use in the Company's enhanced recovery projects currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, the Company expects to avoid any payments for deficiencies. As of December 31, 2008, future commitments under the purchase agreements amounted to $151.1 million through 2014.

Drilling Contracts—The Company currently has nine drilling rigs under long-term contract, of which four drilling rigs expire in 2009, two in 2010, one in 2011, and two in 2012. The Company also has one workover rig under contract until 2009. All of these rigs are operating in the Rocky Mountains region. As of December 31, 2008, these agreements had total commitments of $131.8 million and early termination would require maximum penalties of $90.5 million. Other drilling rigs working for the Company are not under long-term contracts but instead are under contracts that can be terminated at the end of the well that is currently being drilled.

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

Table of Contents

12. SUBSEQUENT EVENTS

In February 2009, the Company completed a public offering of its common stock under its existing shelf registration statement, selling 8,000,000 shares of common stock at a price of $29.00 per share and providing net proceeds of $222.2 million after underwriters' discounts and commissions and estimated offering expenses. Pursuant to the exercise of the underwriters' overallotment option, the Company sold an additional 450,000 shares of common stock at $29.00 per share, providing net proceeds of $12.5 million. The Company used the net offering proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement. Whiting plans to use a portion of the increased credit availability to fund capital expenditures in its 2009 capital budget. Had the common stock issuance occurred at the beginning of 2008, the number of basic and diluted shares used in the computations of earnings per share would have been 50,759,517 and 50,897,256, respectively, for the year ended December 31, 2008.

13. OIL AND GAS ACTIVITIES

The Company's oil and gas activities for 2008 and 2007 were entirely within the United States. During 2006, the Company had insignificant foreign oil and gas operations. Costs incurred in oil and gas producing activities were as follows (in thousands):

	Year Ended December 31, 2008	2007	2006
Development	$ 914,616	$ 506,057	$ 408,828
Proved property acquisition	294,056	8,128	29,778
Unproved property acquisition	98,841	13,598	38,628
Exploration	42,621	56,741	81,877
Total	$ 1,350,134	$ 584,524	$ 559,111

During 2008, 2007 and 2006, additions to oil and gas properties of $3.5 million, $1.5 million and $2.3 million were recorded for the estimated costs of future abandonment related to new wells drilled or acquired.

Net capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	Year Ended December 31, 2008	2007
Proved oil and gas properties	$ 4,423,197	$ 3,313,777
Unproved oil and gas properties	106,436	55,084
Accumulated depreciation, depletion and amortization	(873,233)	(637,549)
Oil and gas properties, net	$ 3,656,400	$ 2,731,312

Table of Contents

Exploratory well costs that are incurred and expensed in the same annual period have not been included in the table below. The net changes in capitalized exploratory well costs were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Beginning balance at January 1	$ 525	$ 10,194	$ 4,193
Additions to capitalized exploratory well costs pending the determination of proved reserves	12,794	19,203	51,798
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(13,319)	(28,872)	(43,276)
Capitalized exploratory well costs charged to expense	-	-	(2,521)
Ending balance at December 31	$ -	$ 525	$ 10,194

At December 31, 2008, the Company had no costs capitalized for exploratory wells in progress for a period of greater than one year after the completion of drilling.

14. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

For all years presented, the estimates of proved reserves and related valuations were based 100% on reports prepared by the Company’s independent petroleum engineers. The estimates of proved reserves and related valuations as of December 31, 2008 were based on reports prepared by Cawley, Gillespie & Associates, Inc., the Company’s independent petroleum engineers. Proved reserve estimates included herein conform to the definitions prescribed by the U.S. Securities and Exchange Commission. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

As of December 31, 2008, all of the Company’s oil and gas reserves are attributable to properties within the United States. A summary of the Company’s changes in quantities of proved oil and gas reserves for the years ended December 31, 2006, 2007 and 2008, are as follows:

Table of Contents

	Oil (MBbl)	Natural Gas (MMcf)
Balance—January 1, 2006	199,199	386,412
Extensions and discoveries	4,125	19,362
Sales of minerals in place	(1,213)	(983)
Purchases of minerals in place	670	4,009
Production	(9,799)	(32,147)
Revisions to previous estimates	2,053	(57,780)
Balance—December 31, 2006	195,035	318,873
Extensions and discoveries	10,973	40,936
Sales of minerals in place	(1,194)	(10,382)
Purchases of minerals in place	691	-
Production	(9,579)	(30,764)
Revisions to previous estimates	392	8,079
Balance—December 31, 2007	196,318	326,742
Extensions and discoveries	20,395	57,093
Sales of minerals in place	(3,919)	(14,277)
Purchases of minerals in place	513	90,329
Production	(12,448)	(30,419)
Revisions to previous estimates	(20,851)	(74,689)
Balance—December 31, 2008	180,008	354,779
Proved developed reserves:		
December 31, 2006	122,496	226,516
December 31, 2007	127,291	237,030
December 31, 2008	120,961	229,224

As discussed in Employee Benefit Plans, all of the Company's employees participate in the Company's Production Participation Plan. The reserve disclosures above include oil and natural gas reserve volumes that have been allocated to the Production Participation Plan ("Plan"). Once allocated to Plan participants, the interests are fixed. Allocations prior to 1995 consisted of 2%–3% overriding royalty interest, while allocations since 1995 have been 2%–5% of oil and gas sales less lease operating expenses and production taxes from the production allocated to the Plan.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with the provisions of SFAS No. 69. Future cash inflows were computed by applying prices at year end to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming the continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily result in an estimate of the fair value of the Company's oil and gas properties.

Table of Contents

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows (in thousands):

	December 31, 2008	2007	2006
Future cash flows	$ 8,558,178	$ 19,747,430	$ 12,635,239
Future production costs	(4,220,329)	(6,022,667)	(4,248,973)
Future development costs	(982,193)	(1,186,826)	(1,176,778)
Future income tax expense	(474,332)	(3,952,146)	(2,064,596)
Future net cash flows	2,881,324	8,585,791	5,144,892
10% annual discount for estimated timing of cash flows	(1,504,876)	(4,574,125)	(2,752,650)
Standardized measure of discounted future net cash flows	$ 1,376,448	$ 4,011,666	$ 2,392,242

Future cash flows as shown above are reported without consideration for the effects of open hedge contracts at each period end. If the effects of hedging transactions were included in the computation, then undiscounted future cash flows would have increased by $345.9 million in 2008, decreased by $81.8 million in 2007, and increased by $2.3 million in 2006.

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	December 31, 2008	2007	2006
Beginning of year	$ 4,011,665	$ 2,392,242	$ 2,882,901
Sale of oil and gas produced, net of production costs	(987,682)	(547,744)	(542,383)
Sales of minerals in place	(54,735)	(72,360)	(30,520)
Net changes in prices and production costs	(4,059,904)	2,261,006	(579,948)
Extensions, discoveries and improved recoveries	259,930	440,337	162,969
Development costs, net	108,922	(4,030)	(212,076)
Purchases of mineral in place	135,288	17,098	29,663
Revisions of previous quantity estimates	(289,381)	43,019	(167,956)
Net change in income taxes	1,851,178	(757,127)	561,302
Accretion of discount	401,167	239,224	288,290
End of year	$ 1,376,448	$ 4,011,665	$ 2,392,242

Average wellhead prices in effect at December 31, 2008, 2007 and 2006 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation were as follows:

	2008	2007	2006
Oil (per Bbl)	$ 38.51	$ 88.62	$ 54.81
Natural Gas (per Mcf)	$ 4.58	$ 6.31	$ 5.41

Table of Contents

15. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2008 and 2007 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Year ended December 31, 2008:				
Oil and natural gas sales	$ 286,731	$ 390,536	$ 425,392	$ 213,821
Operating profit (1)	162,828	252,198	258,224	36,986
Net income	62,314	80,449	112,417	(3,037)
Basic net income per share	1.47	1.90	2.66	(0.07)
Diluted net income per share	1.47	1.90	2.65	(0.07)

	Three Months Ended			
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Year ended December 31, 2007:				
Oil and natural gas sales	$ 159,714	$ 192,646	$ 205,594	$ 251,063
Operating profit (1)	56,474	79,249	89,617	129,593
Net income	10,666	26,471	47,713	45,750
Basic net income per share	0.29	0.72	1.14	1.08
Diluted net income per share	0.29	0.72	1.13	1.08

(1) Oil and natural gas sales less lease operating expense, production taxes and depreciation, depletion and amortization.

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Table of Contents

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of the end of the year ended December 31, 2008. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of the end of the year ended December 31, 2008 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control Over Financial Reporting. The report of management required under this Item 9A is contained in Item 8 of this Annual Report on Form 10-K under the caption “Management’s Annual Report on Internal Control Over Financial Reporting”.

Attestation Report of Registered Public Accounting Firm. The attestation report required under this Item 9A is contained in Item 8 of this Annual Report on Form 10-K under the caption “Report of Independent Registered Public Accounting Firm”.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

On February 18, 2009, the Compensation Committee of the Board of Directors of Whiting Petroleum Corporation (the “Company”) approved grants to certain executive officers of the Company of options to purchase shares of common stock of the Company. The options have an exercise price of $25.51, the fair market value of the Company’s common stock on the grant date. The options vest one-third on each of the first three anniversaries of the grant date and expire on the tenth anniversary of the grant date. The named executive officers of the Company set forth below received the number of options set forth below:

Name	Position	Shares
James J. Volker	Chairman, President and Chief Executive Officer	74,860
James T. Brown	Senior Vice President, Operations	16,535
Michael J. Stevens	Vice President and Chief Financial Officer	24,953

The amounts payable to these executive officers are not determinable because the value of the options are subject to the Company's future stock price. A copy of the form of award agreement used to grant such options is filed as Exhibit 10.14 to this Annual Report on Form 10-K and is incorporated by reference herein.

Table of Contents

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information included under the captions “Election of Directors,” “Board of Directors and Corporate Governance” and “Section 16(a) Beneficial Ownership Reporting Compliance” in our definitive Proxy Statement for Whiting Petroleum Corporation’s 2009 Annual Meeting of Stockholders (the “Proxy Statement”) is hereby incorporated herein by reference. Information with respect to our executive officers appears in Part I of this Annual Report on Form 10-K.

We have adopted the Whiting Petroleum Corporation Code of Business Conduct and Ethics that applies to our directors, our Chairman, President and Chief Executive Officer, our Chief Financial Officer, our Controller and Treasurer and other persons performing similar functions. We have posted a copy of the Whiting Petroleum Corporation Code of Business Conduct and Ethics on our website at www.whiting.com. The Whiting Petroleum Corporation Code of Business Conduct and Ethics is also available in print to any stockholder who requests it in writing from the Corporate Secretary of Whiting Petroleum Corporation. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding amendments to, or waivers from, the Whiting Petroleum Corporation Code of Business Conduct and Ethics by posting such information on our website at www.whiting.com.

We are not including the information contained on our website as part of, or incorporating it by reference into, this report.

Item 11. Executive Compensation

The information required by this Item is included under the captions “Board of Directors and Corporate Governance – Compensation Committee Interlocks and Insider Participation,” “Board of Directors and Corporate Governance – Director Compensation,” “Compensation Discussion and Analysis,” “Compensation Committee Report” and “Executive Compensation” in the Proxy Statement and is hereby incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item with respect to security ownership of certain beneficial owners and management is included under the caption “Principal Stockholders” in the Proxy Statement and is hereby incorporated by reference. The following table sets forth information with respect to compensation plans under which equity securities of Whiting Petroleum Corporation are authorized for issuance as of December 31, 2008.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities

			reflected in the first column)
Equity compensation plans approved by security holders(1)	-	N/A	1,510,261(2)
Equity compensation plans not approved by security holders	-	N/A	-
Total	-	N/A	1,510,261(2)

(1) Includes only the Whiting Petroleum Corporation 2003 Equity Incentive Plan.
(2) Excludes 258,764 shares of restricted common stock previously issued for which the restrictions have not lapsed.

Table of Contents

Item 13. Certain Relationships, Related Transactions and Director Independence

The information required by this Item is included under the caption "Board of Directors and Corporate Governance – Transactions with Related Persons" and "Board of Directors and Corporate Governance – Independence of Directors" in the Proxy Statement and is hereby incorporated by reference.

Item 14. Principal Accounting Fees and Services

The information required by this Item is included under the caption "Ratification of Appointment of Independent Registered Public Accounting Firm" in the Proxy Statement and is hereby incorporated by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial statements – The following financial statements and the report of independent registered public accounting firm are contained in Item 8.

a. Report of Independent Registered Public Accounting Firm

b. Consolidated Balance Sheets as of December 31, 2008 and 2007

c. Consolidated Statements of Income for the Years ended December 31, 2008, 2007 and 2006

d. Consolidated Statements of Cash Flows for the Years ended December 31, 2008, 2007 and 2006

e. Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Years ended December 31, 2008, 2007 and 2006

f. Notes to Consolidated Financial Statements

2. Financial statement schedules – The following financial statement schedule is filed as part of this Annual Report on Form 10-K:

a. Schedule I – Condensed Financial Information of Registrant

All other schedules are omitted since the required information is not present, or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or the notes thereto.

3. Exhibits – The exhibits listed in the accompanying index to exhibits are filed as part of this Annual Report on Form 10-K.

(b) Exhibits

Table of Contents

The exhibits listed in the accompanying exhibit index are filed (except where otherwise indicated) as part of this report.

(c) Financial Statement Schedules.

Table of Contents

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

WHITING PETROLEUM CORPORATION
CONDENSED FINANCIAL STATEMENTS OF THE PARENT COMPANY

CONDENSED BALANCE SHEETS
(In thousands)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets	$ 2,859	$ 4,530
Investment in subsidiaries	1,187,019	919,186
Intercompany receivable	1,249,869	1,256,550
TOTAL	$ 2,439,747	$ 2,180,266
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities	$ 8,292	$ 2,587
Long-term debt	618,061	617,497
Other long-term liabilities	21,874	23,240
Stockholders' equity	1,791,520	1,536,942
TOTAL	$ 2,439,747	$ 2,180,266

CONDENSED STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31, 2008	2007	2006
Operating expenses:			
General and administrative	$ 3,619	$ 4,290	$ 3,367
Interest expense	1,830	2,112	2,671
Equity in earnings of subsidiaries	255,504	134,636	160,410
Income before income taxes	250,055	128,234	154,372
Income tax benefit	(2,088)	(2,366)	(1,992)
Net income	$ 252,143	$ 130,600	$ 156,364

See notes to condensed financial statements.

Table of Contents

Schedule I

WHITING PETROLEUM CORPORATION
CONDENSED FINANCIAL STATEMENTS OF THE PARENT COMPANY

CONDENSED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2008	2007	2006
Cash flows provided by (used in) operating activities	$ 8,883	$ 4,633	$ (846)
Cash flows from investing activities			
Investment in subsidiaries	-	-	-
Cash flows from financing activities:			
Intercompany receivable	(5,647)	(1,659)	4,233
Other financing activities	(3,236)	(2,974)	(3,387)
Net cash (used in) provided by financing activities	(8,883)	(4,633)	846
Net change in cash and cash equivalents	-	-	-
Cash and cash equivalents:			
Beginning of period	-	-	-
End of period	$ -	$ -	$ -
NONCASH INVESTING ACTIVITES:			
Conveyance to Whiting USA Trust I increasing investment in subsidiaries	$ 111,223	$ -	$ -
Sale of Whiting USA Trust I units decreasing investment in subsidiaries	$ (93,683)	$ -	$ -
Distributions from Whiting USA Trust I decreasing investment in subsidiaries	$ (5,212)	$ -	$ -
NONCASH FINANCING ACTIVITES:			
Conveyance to Whiting USA Trust I decreasing intercompany receivable	$ (111,223)	$ -	$ -
Sale of Whiting USA Trust I units increasing intercompany receivable	$ 93,683	$ -	$ -
Distributions from Whiting USA Trust I increasing intercompany receivable	$ 5,212	$ -	$ -
Issuance of common stock increasing stockholders' equity	$ -	$ 210,394	$ -
Issuance of common stock decreasing intercompany receivable	$ -	$ (210,394)	$ -

See notes to condensed financial statements.

NOTES TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Condensed Financial Statements - The condensed financial statements of Whiting Petroleum Corporation (the "Registrant" or "Parent Company") do not include all of the information and notes normally included with financial statements prepared in accordance with GAAP. These condensed financial statements, therefore, should be read in conjunction with the consolidated financial statements and notes thereto of the Registrant, included elsewhere in this 2008 Annual Report on Form 10-K. For purposes of these condensed financial statements, the Parent Company's investments in wholly-owned subsidiaries are accounted for under the equity method.

Table of Contents

Restricted Assets of Registrant - Except for limited exceptions, including the payment of interest on the senior notes, Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") credit agreement restricts the ability of the subsidiaries to make any dividends, distributions or other payments to the Parent Company. The restrictions apply to all of the net assets of the subsidiaries. Accordingly, these condensed financial statements have been prepared pursuant to Rule 5-04 of Regulation S-X of the Securities Exchange Act of 1934, as amended.

Reclassifications - Certain prior period balances were reclassified to conform to the current year presentation, and such reclassifications had no impact on net income or stockholders' equity previously reported.

2. LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

The Parent Company's long-term debt and other long-term liabilities consisted of the following at December 31, 2008 and 2007 (in thousands):

	December 31, 2008	December 31, 2007
Long-term debt:		
7% Senior Subordinated Notes due 2014	$ 250,000	$ 250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,541 and $1,966, respectively	218,459	218,034
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $397 and $537, respectively	149,602	149,463
Other long-term liabilities:		
Tax sharing liability	21,575	23,070
Other	299	170
Total long-term debt and other long-term liabilities	$ 639,935	$ 640,737

Scheduled maturities of the Parent Company's long-term debt and other long-term liabilities as of December 31, 2008, were as follows (in thousands):

2009	2010	2011	2012	2013	Thereafter	Total
$ 2,112	$ 1,961	$ 1,826	$ 151,685	$ 221,577	$ 264,824	$ 643,985

For further information on the Senior Subordinated Notes and tax sharing liability, refer to the Long-Term Debt and Related Party Transactions notes to the consolidated financial statements of the Registrant.

3. WHITING USA TRUST I

On April 30, 2008, the Parent Company 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, and providing net proceeds of $214.9 million after underwriters' discounts and commissions and offering expenses. The 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. The Parent Company used the offering net proceeds to reduce a portion of the debt outstanding under Whiting Oil and Gas' credit agreement. Immediately prior to the closing of the offering, Whiting Oil and Gas and Equity Oil Company conveyed a term net profits interest in certain of its oil and natural gas properties to the Trust in exchange for 13,863,889 Trust units, which Trust units were in turn transferred from Whiting Oil and Gas to the Parent Company. The Parent Company retained 15.8%, or 2,186,389 Trust units, of the total Trust units issued and outstanding.

Table of Contents

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 Trust will soon thereafter wind up its affairs and terminate.

4. SUBSEQUENT EVENT

In February 2009, the Parent Company completed a public offering of its common stock under its existing shelf registration statement, selling 8,000,000 shares of common stock at a price of $29.00 per share and providing net proceeds of $222.2 million after underwriters' discounts and commissions and estimated offering expenses. Pursuant to the exercise of the underwriters' overallotment option, the Parent Company sold an additional 450,000 shares of common stock at $29.00 per share, providing net proceeds of $12.5 million. The Parent Company used the net offering proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement. The Parent Company plans to use a portion of the increased credit availability to fund capital expenditures in its 2009 capital budget. Had the common stock issuance occurred at the beginning of 2008, the number of basic and diluted shares used in the computations of earnings per share would have been 50,759,517 and 50,897,256, respectively, for the year ended December 31, 2008

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Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 25th day of February, 2009.

WHITING PETROLEUM CORPORATION

By /s/ James J. Volker
James J. Volker
Chairman, President and Chief Executive Officer

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

Signature	Title	Date
/s/ James J. Volker James J. Volker	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2009
/s/ Michael J. Stevens Michael J. Stevens	Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2009
/s/ Brent P. Jensen Brent P. Jensen	Controller and Treasurer (Principal Accounting Officer)	February 25, 2009
/s/ Thomas L. Aller Thomas L. Aller	Director	February 25, 2009
/s/ D. Sherwin Artus D. Sherwin Artus	Director	February 25, 2009
/s/ Thomas P. Briggs Thomas P. Briggs	Director	February 25, 2009
/s/ William N. Hahne William N. Hahne	Director	February 25, 2009
	Director	February 25, 2009

/s/ Graydon D. Hubbard Graydon D. Hubbard		
/s/ Palmer L. Moe Palmer L. Moe	Director	February 25, 2009

106

Table of Contents

EXHIBIT INDEX

Exhibit Number	Exhibit Description
(3.1)	Amended and Restated Certificate of Incorporation of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(3.2)	Amended and Restated By-laws of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 (File No. 001-31899)].
(3.3)	Certificate of Designations of the Board of Directors Establishing the Series and Fixing the Relative Rights and Preferences of Series A Junior Participating Preferred Stock [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated February 23, 2006 (File No. 001-31899)].
(4.1)	Third Amended and Restated Credit Agreement, dated as of August 31, 2005, among Whiting Oil and Gas Corporation, Whiting Petroleum Corporation, the financial institutions listed therein and JPMorgan Chase Bank, N.A., as Administrative Agent [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated August 31, 2005 (File No. 001-31899)].
(4.2)	Indenture, dated May 11, 2004, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting Programs, Inc., Equity Oil Company and The Bank of New York Trust Company, N.A., as successor trustee [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 (File No. 001-31899)].
(4.3)	Subordinated Indenture, dated as of April 19, 2005, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting Programs, Inc., Equity Oil Company and The Bank of New York Trust Company, N.A., as successor trustee [Incorporated by reference to Exhibit 4.4 to Whiting Petroleum Corporation's Registration Statement on Form S-3 (Reg. No. 333-121615)].
(4.4)	First Supplemental Indenture, dated as of April 19, 2005, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Equity Oil Company, Whiting Programs, Inc. and The Bank of New York Trust Company, N.A., as successor trustee [Incorporated by reference to Exhibit 4.2 to Whiting Petroleum Corporation's Current Report on Form 8-K dated April 11, 2005 (File No. 001-31899)].
(4.5)	Indenture, dated October 4, 2005, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and The Bank of New York Trust Company, N.A., as successor trustee [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 4, 2005 (File No. 001-31899)].
(4.6)	Rights Agreement, dated as of February 23, 2006, between Whiting Petroleum Corporation and Computershare Trust Company, Inc. [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated February 23, 2006 (File No. 001-31899)].
(10.1)*	

	Whiting Petroleum Corporation 2003 Equity Incentive Plan, as amended through October 23, 2007 [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 23, 2007 (File No. 001-31899)].
(10.2)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for time-based vesting awards prior to October 23, 2007 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 (File No. 001-31899)].

Table of Contents

(10.3)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for performance vesting awards prior to October 23, 2007 and prior to February 23, 2008 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 001-31899)].
(10.4)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for performance vesting awards on and after October 23, 2007 [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 23, 2007 (File No. 001-31899)].
(10.5)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for time-based vesting awards on and after October 23, 2007 [Incorporated by reference to Exhibit 10.4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 23, 2007 (File No. 001-31899)].
(10.6)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for performance vesting awards on and after February 23, 2008 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 001-31899)].
(10.7)*	Whiting Petroleum Corporation Production Participation Plan, as amended and restated February 4, 2008 [Incorporated by reference to Exhibit 10.6 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 001-31899)].
(10.8)	Tax Separation and Indemnification Agreement between Alliant Energy Corporation, Whiting Petroleum Corporation and Whiting Oil and Gas Corporation [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.9)*	Summary of Non-Employee Director Compensation for Whiting Petroleum Corporation.
(10.10)*	Production Participation Plan Credit Service Agreement, dated February 23, 2007, between Whiting Petroleum Corporation and James J. Volker [Incorporated by reference to Exhibit 10.7 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 001-31899)].
(10.11)*	Amended and Restated Production Participation Plan Supplemental Payment Agreement, dated January 14, 2008, between Whiting Petroleum Corporation and J. Douglas Lang [Incorporated by reference to Exhibit 10.6 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 001-31899)].
(10.12)*	Form of Indemnification Agreement for directors and executive officers of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 10.10 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 (File No. 001-31899)].
(10.13)*	Form of Executive Excise Tax Gross-Up Agreement for executive officers of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated January 13, 2009 (File No. 001-31899)].
(10.14)*	

	Form of Stock Option Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan.
(12.1)	Statement regarding computation of ratios of earnings to fixed charges.
(21)	Subsidiaries of Whiting Petroleum Corporation.
(23.1)	Consent of Deloitte & Touche LLP.
(23.2)	Consent of Cawley, Gillespie & Associates, Inc., Independent Petroleum Engineers.
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Certification of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.

Table of Contents

(32.2)	Certification of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
(99.1)	Proxy Statement for the 2009 Annual Meeting of Stockholders, to be filed within 120 days of December 31, 2008 [To be filed with the Securities and Exchange Commission under Regulation 14A within 120 days after December 31, 2008; except to the extent specifically incorporated by reference, the Proxy Statement for the 2009 Annual Meeting of Stockholders shall not be deemed to be filed with the Securities and Exchange Commission as part of this Annual Report on Form 10-K].

* A management contract or compensatory plan or arrangement.