WHITING PETROLEUM CORP
Form 10-K
February 28, 2007

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

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

For the fiscal year ended December 31, 2006

or

o **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, $.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 þ No o

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 o No þ

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 þ No o

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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act). (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2006: $1,540,817,968.

Number of shares of the registrant s common stock outstanding at February 15, 2007: 36,947,681 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2007 Annual Meeting of Stockholders are incorporated by reference into Part III.

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CERTAIN DEFINITIONS

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

We have included below the definitions for certain crude oil and natural gas 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.

Bcf One billion cubic feet of natural gas.

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.

BOE/d One BOE per day.

Bopd Barrels of oil or other liquid hydrocarbons per day.

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.

MBOE One thousand BOE.

MBOE/d One thousand BOE per day.

Mcf One thousand cubic feet of natural gas.

Mcf/d One Mcf per day.

MMbbl One million barrels of oil or other liquid hydrocarbons.

MMBOE One million BOE.

MMbtu One million British Thermal Units.

MMcf One million cubic feet of natural gas.

NGLs Natural gas liquids.

PDNP Proved developed nonproducing.

PDP Proved developed producing.

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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 Securities and Exchange Commission (SEC) guidelines, 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.

working interest The interest in an 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 to share in production, subject to all royalties, overriding royalties and other burdens and to share in all costs of exploration, development and operations and all risks in connection therewith.

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PART I

Item 1. Business

Overview

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

Since our inception in 1980, we have built a strong asset base and achieved steady growth through property acquisitions, development and exploration activities. As of December 31, 2006, our estimated proved reserves totaled 248.1 MMBOE, representing a 6% decrease in our proved reserves since December 31, 2005. Our estimated December 2006 average daily production was 40.5 MBOE/d, which remained consistent with December 2005 average daily production and implied an average reserve life of approximately 16.8 years.

The following table summarizes our estimated proved reserves by core area, the corresponding pre-tax PV10% value, our standardized measure of discounted future net cash flows as of December 31, 2006, and our December 2006 average daily production:

	Proved Reserves					December 2006 Average Daily
Core Area	Oil (MMbbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value[1] (In millions)	Production (MBOE/d)
Permian Basin	103.1	78.3	116.1	89%	$ 1,345.3	12.6
Rocky Mountains	37.1	96.9	53.2	70%	$ 816.4	12.6
Mid-Continent	47.4	36.4	53.5	88%	$ 771.8	5.2
Gulf Coast	2.2	62.2	12.6	18%	$ 211.6	6.4
Michigan	5.2	45.1	12.7	41%	$ 207.1	3.7
Total	**195.0**	**318.9**	**248.1**	**79%**	**$ 3,352.2**	**40.5**
Discounted Future Income Taxes					(960.0)	
Standardized Measure of Discounted Future Net Cash Flows					**$ 2,392.2**	

(1) 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.

We expect to continue to build on our successful acquisition track record and seek property acquisitions that complement our existing core properties. Additionally, we believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with significant organic growth opportunities. During 2006, we incurred $559.1 million in acquisition, development and exploration activities, including $455.0 million for the drilling of 437 gross (322.1 net) wells. Of these new wells, 418 resulted in productive completions and 19 were unsuccessful, yielding a 96% success rate. We have budgeted $350.0 million for development and exploration drilling expenditures in 2007.

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.

2006 Acquisitions. 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 this transaction, the operator will pay 100% of our drilling and completion costs for the first three wells in the project.

On August 15, 2006, we acquired 65 producing properties, a gathering line, gas processing plant and 30,437 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 net production from the properties was 0.6 MBOE/d as of the acquisition effective date. We operate 85% of the acquired properties.

On June 1, 2006, we acquired the Postle field oil gathering system and oil transportation line extending 13 miles from the eastern side of the Postle field to a connection point with an interstate oil pipeline in Hooker, Oklahoma. We purchased the oil gathering system and pipeline for $5.3 million.

We funded our 2006 acquisitions with cash on hand and borrowings under Whiting Oil and Gas Corporation s credit agreement.

2006 Divestitures. During 2006, we sold our interests in several non-core properties for an aggregate amount of $24.4 million in cash for total estimated proved reserves of 1.4 MMBOE as of the effective dates of the divestitures. 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 net production from the divested property interests was 0.4 MBOE/d as of the effective dates of disposition, and we recognized a pre-tax gain on sale of $12.1 million related to these divestitures.

2005 Acquisitions. We completed four separate acquisitions of producing properties during 2005. The combined purchase price for these four acquisitions was $897.7 million for total estimated proved reserves as of the effective dates of the acquisitions of 133.7 MMBOE, resulting in a cost of $6.72 per BOE of estimated proved reserves.

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 largely through the acquisition of additional reserves in our core areas. Based on the extensive property base we have built, we now have several economically attractive opportunities to exploit and develop within our oil and gas properties and several opportunities to explore our acreage positions for production growth and additional proved reserves. Specifically, we have focused, and plan to continue to focus, on the following:

Developing and Exploiting Existing Properties. Our existing property base and our acquisitions over the past three years have provided us with significant low-risk opportunities for exploitation and development drilling. As of

December 31, 2006, we have identified a drilling inventory of approximately 900 gross wells that we believe will add substantial production over the next five years. Our drilling inventory consists largely of the development of our proved undeveloped reserves on which we have spent significant time evaluating the costs and expected results. Additionally, we have several opportunities to apply enhanced recovery techniques that we expect will increase proved reserves and extend the productive lives of our mature fields. Over the next five years, we anticipate significant increases in production from the North Ward Estes field and Postle field properties we acquired in 2005 through the use of secondary and tertiary recovery techniques, including water and CO_2 floods.

Growing Through Accretive Acquisitions. Since our initial public offering in November 2003, we have completed twelve acquisitions of producing properties totaling 207.7 MMBOE of estimated total proved reserves. Our experienced team of management, 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. As a result of our disciplined approach, we have achieved significant growth in our core areas at an average cost of $7.02 per BOE of proved reserves through these twelve acquisitions, not including future costs to develop proved undeveloped reserves.

Pursuing High-Return Organic Reserve Additions. We plan to allocate approximately 75% of our $350.0 million capital budget for 2007 to the development of our existing proved reserves. The remaining 25% will be invested in higher risk drilling, including field extensions drilled outside the current limits of our development projects as well as new exploration, which we believe will increase our proved reserves and future cash flow. We expect to add reserves at costs competitive with our acquisitions. The development of large, unconventional resource plays such as our Piceance basin and Robinson Lake projects have become a central objective of ours. These projects allow us to leverage our technical team s experience to focus on conventional drilling projects such as our Red River gas play in which we can utilize our 3-D seismic data and other advanced exploration techniques to reduce risk and deliver a high return on investment. We own interests in 897,133 gross (484,495 net) undeveloped acres as well as additional rights to deeper horizons within many of our developed acreage positions.

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. To support cash flow generation on our existing properties and secure acquisition economics, 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, 2006, we had interests in 8,437 gross (3,659 net) productive wells across 976,379 gross (472,144 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 for success in executing our strategy because we are not dependent on any particular producing regions or geological formations. As a result of our acquisitions of the North Ward Estes field and Postle field properties in 2005 we have enhanced the production stability and reserve life of our developed reserves. Additionally, these properties contain identifiable growth opportunities to significantly increase production.

Experienced Management Team. Our management team averages over 30 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 25 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 1,580 square miles of 3-D seismic data, digital well logs and other subsurface information. This data is analyzed with state of the art geophysical and geological computer resources dedicated to the accurate and efficient characterization of the subsurface oil and gas reservoirs that comprise our asset base. Computer applications enable us to quickly generate reports and schematics on our wells. In addition, our information systems enable us to update our production databases through daily uploads from hand held computers in the field. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

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Proved Reserves

Our estimated proved reserves as of December 31, 2006 are summarized in the table below.

	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Future Capital Expenditures (In thousands)
Permian Basin:					
PDP	32.0	39.5	38.6	33%	
PDNP	20.7	9.9	22.2	19%	
PUD	50.4	28.9	55.3	48%	
Total Proved	**103.1**	**78.3**	**116.1**	**100%**	**$ 713.7**
Rocky Mountains:					
PDP	32.1	66.5	43.1	81%	
PDNP	1.2	5.1	2.1	4%	
PUD	3.8	25.3	8.0	15%	
Total Proved	**37.1**	**96.9**	**53.2**	**100%**	**$ 84.2**
Mid-Continent:					
PDP	20.5	23.2	24.3	45%	
PDNP	11.9	5.5	12.9	24%	
PUD	15.0	7.7	16.3	31%	
Total Proved	**47.4**	**36.4**	**53.5**	**100%**	**$ 310.0**
Gulf Coast:					
PDP	1.4	34.1	7.1	56%	
PDNP	0.2	7.0	1.4	11%	
PUD	0.6	21.1	4.1	33%	
Total Proved	**2.2**	**62.2**	**12.6**	**100%**	**$ 43.1**
Michigan:					
PDP	1.6	34.0	7.3	57%	
PDNP	0.8	1.7	1.1	9%	
PUD	2.8	9.4	4.3	34%	
Total Proved	**5.2**	**45.1**	**12.7**	**100%**	**$ 25.8**

Total Company:						
PDP	87.6	197.3	120.4	49%		
PDNP	34.8	29.2	39.7	16%		
PUD	72.6	92.4	88.0	35%		
Total Proved	**195.0**	**318.9**	**248.1**	**100%**	**$**	**1,176.8**

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. Our marketing of oil and gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. 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. During 2005, sales to Teppco Crude Oil LLC accounted for 10% of our total oil and natural gas sales. In 2004, no single customer was responsible for generating 10% or more of our total oil and natural gas sales.

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Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Whiting Oil and Gas Corporation s 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 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 and Sale of Natural Gas

The Federal Energy Regulatory Commission (FERC) regulates the transportation and 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 sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation 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. 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, 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.

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 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.

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 sales of crude oil 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. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. As a result, the FERC in February 2003 increased the index slightly, effective July 2001. 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.

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 and 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:

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, 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.

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 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 Clean Water Act 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. The due date for having plans completed and control devices in place was extended on December 12, 2005 with the new compliance date being October 31, 2007. On December 26, 2006 the EPA proposed an additional extension of the compliance dates until July 1, 2009 for both completion and implementation of the Plan. This proposed rule is expected to be finalized in the near future. The extension will allow time for the EPA to complete additional rule amendments and guidance documents. We believe that our operations comply in all material respects with the requirements of the Clean Water Act 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 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.

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, 2006, we had 359 full-time employees, including 27 senior level geoscientists and 35 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.

Item 1A. Risk Factors

You should carefully consider each of the risks described below, 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.

A substantial or extended decline in oil and gas prices may adversely affect our business, financial condition or results of operations.

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. These markets will likely continue to be volatile in the future. 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.

Lower oil and gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and gas that we can produce economically. A substantial or extended decline in oil or gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. 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.

Drilling for and producing oil and 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 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 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 . . . 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 equipment, including drilling rigs, and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and gas prices; and
- title problems.

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Our acquisition activities may not be successful.

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

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, 2006, undeveloped reserves comprised 54% of the North Ward Estes field s total estimated proved reserves and 34% of Postle field s estimated total proved reserves. In order to fully develop these reserves, we expect to incur future development costs of $656.0 million at the North Ward Estes field and $302.6 million at the Postle field. During 2006, the estimated capital expenditures necessary to develop the proved reserves at the North Ward Estes field and Postle field increased substantially. The increase was due to several factors including equipment and service cost inflation, higher CO_2 unit costs and volumes, higher costs associated with the expanded scope of previously identified projects as well as new projects identified during 2006. Together, these fields encompass 82% of our estimated total future development costs related to proved reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO_2 injection installations, the success of which is less predictable than traditional development techniques. Therefore, ultimate recoveries from these fields may not match current expectations.

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 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.

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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. During 2006 and 2005, we completed five separate acquisitions of producing properties with a combined purchase price of $923.7 million for estimated proved reserves as of the effective dates of the acquisitions of 135.1 MMBOE, representing an average cost of $6.84 per BOE of estimated proved reserves. 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 gas prices;
- estimates of operating costs;
- estimates 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.

If oil and 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, 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.

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

As of December 31, 2006, we had $380.0 million in outstanding consolidated indebtedness under Whiting Oil and Gas Corporation s credit agreement with $495.0 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 Corporation s credit agreement.

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

increasing our vulnerability to general adverse economic and industry conditions and detracting from our ability to withstand successfully a downturn in our business or the economy generally;

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 Corporation s 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 Corporation s 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 bank debt.

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, 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 Corporation s 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 Corporation s credit agreement contain various restrictive covenants that limit our management s discretion in operating our business. 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 restrict subsidiaries taken as a whole;

engage in transactions with affiliates;

enter into hedging contracts;

create unrestricted subsidiaries; and

enter into sale and leaseback transactions.

In addition, Whiting Oil and Gas Corporation s credit agreement also requires us to maintain a certain working capital ratio and a certain debt to EBITDAX (as defined in the credit agreement) ratio.

If we fail to comply with the restrictions in the indentures governing our senior subordinated notes or Whiting Oil and Gas Corporation s 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 development and exploration 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 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 gas reserves. To date, we have financed capital expenditures primarily with bank borrowings and cash generated by operations. We intend to finance our future capital expenditures with cash flow from operations and our existing financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

our proved reserves;

the level of oil and gas we are able to produce from existing wells;

the prices at which oil and 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 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 exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and gas reserves.

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 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 Annual Report on Form 10-K.

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 gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and gas reserves are inherently imprecise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and 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 Annual Report on Form 10-K. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and 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 referred to in this Annual Report on Form 10-K is the current market value of our estimated oil and 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, 2006 would have decreased from $2,392.2 million to $2,382.1 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, 2006 would have decreased from $2,392.2 million to $2,340.9 million.

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.

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. The analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects.

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 gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and gas, including the possibility of:

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

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

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

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

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

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, 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 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 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.

Market conditions or the unavailability 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 gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of gas pipeline or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver 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 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.

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 substantially increase our

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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 the 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. 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. 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.

Unless we replace our oil and gas reserves, our reserves and production will decline, which would adversely affect our cash flows and income.

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 gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and gas reserves and production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.

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

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, our Chairman, President and Chief Executive Officer; James T. Brown, our Vice President, 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 on a timely basis our exploration and development plans within our budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development and exploration 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 capital available 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 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 for our oil and gas production to reduce our exposure to fluctuations in the price of oil and gas. Our hedging transactions have to date consisted of financially settled crude oil and natural gas forward sales contracts, primarily costless collars, placed with major financial institutions. As of December 31, 2006, we have contracts maturing in 2007 covering the sale of between 410,000 and 450,000 barrels of oil per month and 1,600,000 MMbtu of gas per month. All our oil hedges expire in December of 2008, and all our gas hedges expire in March of 2007. Whiting Oil and Gas Corporation s credit agreement required us to hedge at least 55% of our total forecasted production from the Postle properties and the North Ward Estes properties for the period through March 31, 2007 for gas and December 31, 2008 for oil. These hedges were put in place during the third quarter of 2005. See Quantitative and Qualitative Disclosure about Market Risk Commodity 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 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 would have otherwise received from increases in the price for oil and gas. Furthermore, if we do not engage in hedging transactions, then we may be more adversely affected by declines in oil and gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

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, 2006, the Permian Basin region contributed 116.1 MMBOE (89% oil) of estimated proved reserves to our portfolio of operations, which represented 47% of our total estimated proved reserves. Approximately 96% of the proved reserves of our Permian Basin operations are related to properties in Texas.

North Ward Estes. The North Ward Estes field includes six base leases with 100% working interest in 58,000 gross and net acres in Ward and Winkler Counties, Texas. As of December 31, 2006, there were approximately 935 producing wells and 440 injection wells. 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. We also have the rights to deeper horizons under 34,140 gross acres in the North Ward Estes field. The North Ward Estes properties produced at an estimated average net daily rate of 5,370 Bopd (including NGLs) and 5,880 Mcf/d of gas during the month of December 2006. In the North Ward Estes field, the estimated proved reserves as of December 31, 2006 were 20% PDP, 26% PDNP and 54% PUD.

The North Ward Estes field was initially developed in the 1930 s and full scale waterflooding was initiated in 1955. A CO_2 enhanced recovery project was implemented in the core of the field in 1989, but was terminated in 1996 after a successful top lease by a third party. We reinitiated water injection in 2006 and have successfully re-pressured the pilot area for the resumptions of the CO_2 flood. We began construction of a gas plant to process and separate the CO_2 from the produced gas in the fourth quarter of 2006, and we plan to begin CO_2 injection late in the first quarter of 2007. A contract for the future purchase of significant CO_2 volumes was executed during 2006.

We also have interests in certain other fields within the Permian Basin of Texas and New Mexico, including 2,250 producing oil and gas wells. These properties produced at an estimated average net daily rate of 7,990 Bopd (including NGLs) and 18,340 Mcf/d of gas during the month of December 2006.

Would Have Field. We own an 87% operated working interest in the Would Have field in Howard County, Texas, currently producing from 57 active wells. Discovered in 2001, this field produces from two sub-units of the Clearfork Formation, the Would Have and the Dillard Limestones. Waterflood expansion into the eastern half of the field is currently underway. During 2006 we drilled two successful Varel (San Andres) tests, and plans are underway to participate in a Wolfberry (Wolfcamp & Sprayberry) test on the lease.

Keystone South, Martin and Flying W Fields. We own a 100% working interest and operate these three fields located on the Western edge of the Midland Basin. Production comes from the Clearfork Formation, with additional production from the Wichita, Wolfcamp, Devonian, Silurian, McKee and Ellenburger Formations. During 2006 we drilled a total of seven wells in these fields. Based on the 2006 success, we are planning additional wells for 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, 2006, our estimated proved reserves in the Rocky Mountain region were 53.2 MMBOE (70% oil), which represented 21% of our total estimated proved reserves. Approximately 51% and 31% of the proved reserves of our Rocky Mountain operations are related to assets in North Dakota and Wyoming, respectively.

Robinson Lake Bakken Play. The Bakken Formation is a low permeability, unconventional reservoir consisting of highly oil saturated shale, dolomite and fine grained sand. Horizontal drilling and advanced stimulation techniques have been successfully employed in the drilling of hundreds of wells in the Elm Coulee field in Montana and more recently in the North Dakota portion of the Williston Basin. In early 2005, we embarked on an aggressive leasing program and have since acquired approximately 116,000 gross (81,000 net) acres primarily in Mountrail County, North Dakota for the purpose of developing a Bakken resource drilling program. To date, we have drilled and completed two exploratory wells. We are encouraged by our Bartleson State #44-1H well, which is currently flowing oil and appears to be an economic well. We are currently drilling our third well and conducting a 98 square mile 3-D seismic survey in order to assist in our selection of future drilling locations.

Red River Gas Drilling Program. In 2004 we began acquiring 3-D seismic data over several Red River Formation prospects in the deeper, gas bearing part of the Williston Basin for the purpose of defining structure and reservoir distribution. To date we have acquired seven 3-D surveys in Billings, McKenzie and Williams Counties totaling 165 square miles which we have used to target eight new wells. Eight of these wells have resulted in successful completions with average initial rates of 3,100 Mcf/d. We currently plan to drill four to eight wells during 2007.

Billings Nose Drilling Program. We have established a high concentration of producing wells in the Billings Nose area of Billings County, North Dakota. These assets include the Big Stick Madison Unit and North Elkhorn Ranch Unit along with much of the acreage located between these two fields. We have acquired 99 square miles of 3-D seismic data in this area and have since identified multiple opportunities in a variety of reservoirs including the Red River, Duperow, Bakken and Mission Canyon Formations. In 2006, we drilled one Mission Canyon well in the Big Stick Unit and three horizontal Mission Canyon wells in North Elkhorn Ranch. Additional drilling is planned in both of these units in 2007.

Nisku A Drilling Program. We made a significant exploration discovery in 2004 in western Billings County, North Dakota in the Nisku A zone and drilled ten wells in 2004. In 2005 we drilled eight casing-exit wells and drilled or participated in 13 grass-roots horizontal wells. During 2006 we participated in 20 grass-roots horizontal wells. We plan additional development drilling in the area and are studying the potential for additional recovery through the implementation of a waterflood.

Green River Basin Siberia Ridge. Siberia Ridge is within the greater Wamsutter Arch area of Sweetwater County, Wyoming and produces from a continuous-phase gas accumulation in the Cretaceous Almond Formation at 10,500 feet. In 2004, the spacing rules governing the well density in the Siberia Ridge field were adjusted to allow for up to two wells per 160 acres. This new configuration resulted in a total of 44 additional potential locations on our acreage. Because of lease stipulations on this Federal acreage, drilling operations can be initiated August 1st and must end by February 1st of the following year. We have been able to maintain a single well drilling program by moving the rig between Anderson Canyon (described below) and Siberia Ridge.

Our development program commenced in mid-2005 and continued in 2006 with the drilling of ten new wells. We have implemented a focused effort on the identification, selective perforation and stimulation of the various natural gas productive zones within the Almond Formation in order to optimize production. Completion operations are currently underway with encouraging initial rates.

Green River Basin Anderson Canyon. Anderson Canyon, North Anderson Canyon, Bird Canyon, and McDonald Draw fields are all located on the LaBarge Platform in Southwest Wyoming. We drilled six wells in 2006 and plan to drill ten wells in 2007. Initial results are positive with initial production rates ranging from 500 Mcf/d to over 1,000 Mcf/d. We believe the remaining potential is primarily in the Frontier formation at 8,800 feet.

*Sulphur Creek-Boies Ranch Area, Rio Blanco County, Colorado***.** The Sulphur Creek Area in the North Central Piceance Basin has the potential to be a focal point of our activity through 2009. We acquired the majority of 16,813 gross (3,638 net) acres in the 2004 Equity Oil Company acquisition. We are currently supplementing our leasehold in the area. Drilling by third parties near our leasehold has demonstrated the presence of a continuous-phase gas resource in the Williams Fork Formation with up-hole potential in the Wasatch Formation. We finished the drilling of the first well on the Boies Ranch acreage in early 2007, and we have planned three additional wells for the remainder of the year. An additional 73 Williams Fork locations are planned assuming typical 20 acre spacing. On the Boies Ranch acreage we own the acreage in fee, meaning we own the surface and minerals and there are minimal landowner burdens. As a result, we have a 50% average working interest with a 49% average net revenue interest in the Boies Ranch acreage.

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 recent Covenant Field discovery in Sevier County, Utah. As part of our acquisition of this property, the operator will pay 100% our drilling and completion costs for the first three wells in the project. The first of these three

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has been drilled but did not find commercial quantities of hydrocarbons. The remaining two wells will likely be drilled during 2007.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. As of December 31, 2006, the Mid-Continent region contributed 53.5 MMBOE (88% oil) of proved reserves to our portfolio of operations, which represented 22% of our total estimated proved reserves. 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 acres (24,225 net) with working interests of 94% to 100%. Three of the units are currently active CO_2 enhanced recovery projects. As of December 31, 2006, there were 127 producing wells and 107 injection wells completed in the Morrow zone at 6,100 feet. The Postle field is the largest Morrow oil field in the U.S. The Postle properties produced at an estimated average net daily rate of 4,112 Bopd (including NGLs) and 930 Mcf/d of gas during the month of December 2006. In the Postle field, the estimated proved reserves as of December 31, 2006 were 40% PDP, 26% PDNP and 34% PUD.

The Postle field was initially developed in the early 1960 s and unitized for waterflood in 1967. Enhanced recovery projects using CO_2 were initiated in 1995 and continue in three of the five units. Operations are underway to expand CO_2 injection into the rest of the units, with four drilling rigs and three workover rigs in the field. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells.

We are the sole owner of the Dry Trails Gas Plant located in the Postle field. This gas processing plant separates CO_2 gas from the produced wellhead mixture of hydrocarbon and CO_2 gas, so that the CO_2 gas can be reinjected into the producing formation. Construction began in mid-2006 to increase the plant capacity from its current capacity of 40,000 Mcf/d to 80,000 Mcf/d by the fourth quarter of 2007 to support the expanded CO_2 injection projects.

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

Gulf Coast Region

Our Gulf Coast operations include assets located in Texas, Louisiana and Mississippi. As of December 31, 2006, the Gulf Coast region contributed 12.6 MMBOE (18% oil) of proved reserves to our portfolio of operations, which represented 5% of our total estimated proved reserves. Approximately 80% of the proved reserves of our Gulf Coast operations are related to properties in Texas.

Stuart City Reef Trend. We have an average 65% working interest in five fields in the Stuart City Reef Trend: Word North, Yoakum, Kawitt, Sweet Home, and Three Rivers. Production in the Stuart City Reef Trend comes primarily from the Edwards, Wilcox, and Sligo Formations at depths between 7,000 and 16,000 feet.

In late 2003, we began a combination development and exploration program targeting multiple sandstone gas reservoirs within the Wilcox Formation. We have been active in this area, drilling nine wells in 2005 and three wells in 2006. In addition, we are currently planning to conduct a 40 square mile 3-D seismic program designed to expand this play into new areas. Recent success with vertical Edwards completions has improved the economics of this gas play. For 2007, we are planning to participate in the drilling of up to five vertical Edwards wells with the potential for Wilcox pay to be encountered in each wellbore.

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Vicksburg Trend. Our non-operated holdings in the Vicksburg and Frio Trends are concentrated primarily in the South Midway field in San Patricio County, Texas and the Agua Dulce field. During 2005, we drilled or participated in eleven new wells targeting multiple gas productive sands in the Vicksburg and Frio Formations at depths between 10,000 and 14,500 feet. Results from this program encouraged us to drill seven additional wells in South Midway and one additional well in Agua Dulce during 2006.

Michigan Region

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 the recently acquired Reno gas processing plants. These plants are in good mechanical condition and capable of handling additional production. The West Branch Plant gathers production from the Clayton, West Branch and other smaller fields.

Antrim Production. In northern Michigan, we own an interest in over 50 multi-well Antrim Shale gas projects with proved producing reserves and ongoing development drilling. During 2006, we participated in the drilling and completion of 20 Antrim Shale wells. In 2007, we plan to continue to pursue similar development drilling opportunities.

Conventional Production. Our conventional production is primarily from the Prairie du Chien, Glenwood and Trenton Black River Formations, located in central and southern Michigan. We own interests in 49 fields in this area, of which we operate 24.

In August 2006, we closed on an acquisition of 65 wells producing a total of 638 net Bopd. The acquisition was 99% proved producing reserves, of which 55% was oil. Based on our evaluation of the properties and our experience in Clayton Unit, we are optimistic about the potential upside that may exist in these mature fields.

During late 2005, we drilled two Glenwood/Prarie du Chien (PdC) wells in the Clayton Unit. The target reservoir was the upper PdC, which historically had been the pay interval in the field. Both of these wells encountered hydrocarbons in the Middle interval of the PdC, which had not previously produced. The initial completion in both of these wells was in the middle PdC and both wells still have the original target reservoir behind pipe. We have been encouraged by the results. We assisted a local drilling contractor with the financing necessary to assemble another drilling rig capable of drilling to the PdC. This rig is now drilling the first well in a multi-year drilling program.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2006 by state. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

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	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
California	35,956	10,909	3,273	277	39,229	11,185
Colorado	34,390	18,091	33,984	8,273	68,374	26,364
Kansas	850	561	75,849	74,506	76,699	75,066
Louisiana	41,804	10,700	5,294	2,447	47,098	13,147
Michigan	150,079	71,645	21,601	17,936	171,680	89,580
Montana	38,400	12,448	73,939	32,363	112,339	42,533
North Dakota	152,595	80,939	314,874	199,823	467,469	280,762
Oklahoma	63,249	39,460	171	32	63,420	39,492
Texas	316,527	151,325	93,658	70,031	410,185	223,296
Utah	20,677	11,343	213,254	48,568	233,931	59,911
Wyoming	106,928	56,580	60,039	29,453	166,967	86,299
Other*	14,924	8,143	1,197	786	16,121	8,929
Total	976,379	472,144	897,133	484,495	1,873,512	956,564

* Other includes Alabama, Arkansas, Mississippi, New Mexico and South Dakota.

Production History

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

	Year Ended December 31,		
	2006	2005	2004
Oil production (MMbbls)	9.8	7.0	3.7
Natural gas production (Bcf)	32.1	30.3	25.1
Total production (MMBOE)	15.2	12.1	7.9
Daily production (MBOE/d)	41.5	33.1	21.6
Average sales prices:			
Oil (per Bbl)	$ 57.27	$ 51.26	$ 38.72
Effect of oil hedges on average price (per Bbl)	$ (0.95)	$ (2.72)	$ (1.33)
Oil net of hedging (per Bbl)	$ 56.32	$ 48.54	$ 37.39
Natural gas (per Mcf)	$ 6.59	$ 7.03	$ 5.56
Effect of natural gas hedges on average price (per Mcf)	$ 0.06	$ (0.47)	$
Natural gas net of hedging (per Mcf)	$ 6.65	$ 6.56	$ 5.56

Per BOE data:

Sales price (net of hedging)	$ 50.52	$ 44.70	$ 35.23
Lease operating expenses	$ 12.12	$ 9.24	$ 6.91
Production taxes	$ 3.11	$ 2.99	$ 2.14
Depreciation, depletion and amortization expenses	$ 10.74	$ 8.08	$ 6.89
General and administrative expenses	$ 2.49	$ 2.53	$ 2.45

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Productive Wells

The following table presents our ownership at December 31, 2006 in productive oil and gas wells by region (a net well is our percentage ownership of a gross well).

	Oil Wells		Natural Gas Wells		Total Wells(1)	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	3,375	1,753	363	139	3,738	1,892
Rocky Mountains	1,684	407	410	185	2,094	592
Mid-Continent	449	286	218	98	667	384
Gulf Coast	100	60	715	259	815	319
Michigan	89	67	1,034	405	1,123	472
Total	5,697	2,573	2,740	1,086	8,437	3,659

(1) 103 wells are multiple completions. These 103 wells contain a total of 224 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 the results of 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
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
2005:						
Development	276	18	294	164.7	10.6	175.3
Exploratory	7	7	14	1.3	3.9	5.2
Total	283	25	308	166.0	14.5	180.5

2004:						
Development	157	7	164	73.4	3.7	77.1
Exploratory	3	2	5	1.5	0.2	1.7
Total	160	9	169	74.9	3.9	78.8

Item 3. Legal Proceedings

In the ordinary course of business, we are a claimant or a defendant in various legal proceedings. In the opinion of our management, we do not have any litigation pending or threatened that is material.

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 2006.

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 15, 2007, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	60	Chairman, President and Chief Executive Officer
James T. Brown	54	Vice President, Operations
Bruce R. DeBoer	54	Vice President, General Counsel and Corporate Secretary
J. Douglas Lang	57	Vice President, Reservoir Engineering/Acquisitions
Patricia J. Miller	69	Vice President, Human Resources
David M. Seery	52	Vice President, Land
Michael J. Stevens	41	Vice President and Chief Financial Officer
Mark R. Williams	50	Vice President, Exploration and Development
Brent P. Jensen	37	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 thirty years of experience in the oil and gas industry. Mr. Volker has a degree in finance from the University of Denver, a 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 and, in January 2000, he became Vice President of Operations. Mr. Brown has over thirty 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 a 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.

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 thirty 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 a 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.

Patricia J. Miller joined us in April 1980 as Corporate Secretary and as Secretary to our President, becoming Director of Human Resources in May 1994. In November 2001, she was appointed Vice President of Human

Resources. She served as Corporate Secretary until January 2005. Mrs. Miller attended business school at Otero Junior College in LaJunta, Colorado and at Texas A & I in Kingsville, Texas.

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 twenty-five 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 as 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 twenty-four 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 thirteen years of oil and gas accounting experience and is a Certified Public Accountant. Mr. Jensen holds a Bachelor of Arts degree with an emphasis in accounting and business 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.

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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, 2006		
Fourth Quarter (Ended December 31, 2006)	$50.30	$35.81
Third Quarter (Ended September 30, 2006)	$48.10	$37.30
Second Quarter (Ended June 30, 2006)	$46.95	$33.70
First Quarter (Ended March 31, 2006)	$47.25	$37.41
Fiscal Year Ended December 31, 2005		
Fourth Quarter (Ended December 31, 2005)	$44.91	$36.77
Third Quarter (Ended September 30, 2005)	$46.17	$36.39
Second Quarter (Ended June 30, 2005)	$43.20	$28.19
First Quarter (Ended March 31, 2005)	$46.30	$27.76

On February 15, 2007, there were 919 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 results of operations, financial condition, 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.

We completed our initial public offering in November 2003. Our common stock began trading on the New York Stock Exchange on November 20, 2003. The following graph compares on a cumulative basis changes since November 20, 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 November 20, 2003 in our common stock, the Standard & Poor s Composite 500 Index and the Dow Jones US Oil Companies, Secondary Index.

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	11/20/03	12/31/03	12/31/04	12/31/05	12/31/06
Whiting Petroleum Corporation	$100	$113	$186	$246	$286
Standard & Poor s Composite 500 Index	100	108	117	121	137
Dow Jones US Oil Companies, Secondary Index	100	114	160	263	275

Item 6. Selected Financial Data

The consolidated income statement information for the years ended December 31, 2006, 2005 and 2004 and the consolidated balance sheet information at December 31, 2006 and 2005 are derived from our audited financial statements included elsewhere in this report. The consolidated income statement information for the years ended December 31, 2003 and 2002 and the consolidated balance sheet information at December 31, 2004, 2003 and 2002 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: 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; and Green River Basin, March 31, 2005.

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(dollars in millions except per share data)				
Consolidated Income Statement Information:					
Revenues and other income:					
Oil and natural gas sales	$ 773.1	$ 573.2	$ 281.1	$ 175.7	$ 122.7
Loss on oil and natural gas hedging activities	(7.5)	(33.4)	(4.9)	(8.7)	(3.2)
Gain on sale of oil and gas properties	12.1		1.0		1.0
Gain on sale of marketable securities			4.8		
Interest income and other	1.1	0.6	0.1	0.3	
Total revenues and other income	778.8	540.4	282.1	167.3	120.5
Costs and expenses:					
Lease operating	183.6	111.6	54.2	43.2	32.9
Production taxes	47.1	36.1	16.8	10.7	7.4
Depreciation, depletion and amortization	162.8	97.6	54.0	41.2	43.6
Exploration and impairment	34.5	16.7	6.3	3.2	1.8
General and administrative	37.8	30.6	19.2	13.0	10.3
Change in Production Participation Plan liability	6.2	9.7	1.7	(0.2)	1.7
Phantom equity plan (1)				10.9	
Interest expense	73.5	42.0	15.9	9.2	10.9
Total costs and expenses	545.5	344.3	168.1	131.2	108.6
Income before income taxes and cumulative change in accounting principle	233.3	196.1	114.0	36.1	11.9
Income tax expense (2)	76.9	74.2	44.0	13.9	4.2
Income before cumulative change in accounting principle	156.4	121.9	70.0	22.2	7.7
Cumulative change in accounting principle (3)				(3.9)	
Net income	$ 156.4	$ 121.9	$ 70.0	$ 18.3	$ 7.7
	$ 4.26	$ 3.89	$ 3.38	$ 1.18	$ 0.41

Income per common share before cumulative change in accounting principle, basic					
Income per common share before cumulative change in accounting principle, diluted	$ 4.25	$ 3.88	$ 3.38	$ 1.18	$ 0.41
Net income per common share, basic	$ 4.26	$ 3.89	$ 3.38	$ 0.98	$ 0.41
Net income per common share, diluted	$ 4.25	$ 3.88	$ 3.38	$ 0.98	$ 0.41
Other Financial Information:					
Net cash provided by operating activities	$ 411.2	$ 330.2	$ 134.1	$ 91.9	$ 62.6
Net cash used in investing activities	$ 527.6	$ 1,126.9	$ 524.4	$ 47.6	$ 157.5
Net cash provided by financing activities	$ 116.4	$ 805.5	$ 338.4	$ 4.4	$ 98.7
Ratio of earnings to fixed charges (4)	4.14x	5.64x	8.01x	4.85x	2.08x
Capital expenditures	$ 552.0	$ 1,126.9	$ 530.6	$ 47.6	$ 165.4

	As of December 31, (dollars in millions)				
	2006	**2005**	**2004**	**2003**	**2002**
Consolidated Balance Sheet Information:					
Total assets	$2,585.4	$2,235.2	$1,092.2	$536.3	$448.5
Total debt	$ 995.4	$ 875.1	$ 328.4	$188.0	$265.5
Stockholders equity	$1,186.7	$ 997.9	$ 612.4	$259.6	$122.8

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(1) The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan, pursuant to which our employees received payments valued at $10.9 million in the form of shares of our common stock. The phantom equity plan is now terminated.

(2) We generated Section 29 tax credits of $5.4 million in 2002. Section 29 tax credit provisions of the Internal Revenue Code expired as of December 31, 2002. In 2002, we were able to use our $5.4 million of Section 29 tax credits in the consolidated federal income tax return filed by our former parent, Alliant Energy Corporation, but since these credits would

not have been used in a stand-alone filing, they were recorded as additional paid-in capital as opposed to a reduction in income tax expense.

(3) In 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. This was a one-time charge to net income.

(4) 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.

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

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 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. Some, but not all, of the risks and uncertainties include: declines in oil or gas prices; our level of success in exploitation, exploration, development and production activities; the timing of our exploration and development expenditures, including our ability to obtain drilling rigs; our ability to obtain external capital to finance acquisitions; our ability to identify and complete acquisitions and to successfully integrate acquired businesses, including our ability to realize cost savings from completed acquisitions; unforeseen underperformance of or liabilities associated with acquired properties; inaccuracies of our reserve estimates or our assumptions underlying them; 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; risks related to our level of indebtedness and periodic redeterminations of our borrowing base under our credit agreement; our ability to replace our oil and gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry; 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.

Overview

We are 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. Over the last six years, we have emphasized the acquisition of properties that provided current production and upside potential through further development. Our drilling activity is directed at this development, specifically on projects that we believe provide repeatable successes in particular fields. Our combination of acquisitions and development allows us to direct our capital resources to what we believe to be the most advantageous investments.

We have historically acquired operated and non-operated properties that meet or 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 provided a foothold 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 sale 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.

Our revenue, profitability and future growth rate depend on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas reserves that we can economically produce and our access to capital.

Although independent engineers estimated probable and possible reserves relating to certain 2006, 2005 and prior year producing property acquisitions, we, consistent with our present acquisition practices, have associated all acquisition costs with proved reserves. Because of our substantial recent acquisition activity, our discussion and analysis of our historical financial condition and results of operations for the periods discussed below may not necessarily be comparable with or applicable to our future results of operations. Our historical results include the results from our recent acquisitions beginning on the following dates: 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; and Green River Basin, March 31, 2005.

2006 Acquisitions

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 this transaction, the operator will pay 100% of our drilling and completion costs for the first three wells in the project.

Michigan Properties. On August 15, 2006, we acquired 65 producing properties, a gathering line, gas processing plant and 30,437 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. We operate 85% of the acquired properties.

Oil Pipeline and Gathering System. On June 1, 2006, we acquired the Postle field oil gathering system and oil transportation line extending 13 miles from the eastern side of the Postle field to a connection point with an interstate oil pipeline in Hooker, Oklahoma. We purchased the oil gathering system and pipeline for $5.3 million.

We funded our 2006 acquisitions with cash on hand and borrowings under Whiting Oil and Gas Corporation s credit agreement.

2006 Divestitures

During 2006, we sold our interests in several non-core 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 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.

2005 Acquisitions

North Ward Estes and Ancillary Properties. On October 4, 2005, we acquired the operated interest in the North Ward Estes field in Ward and Winkler counties, Texas, and certain smaller fields located in the Permian Basin. The purchase price was $459.2 million, consisting of $442.0 million in cash and 441,500 shares of our common stock, for estimated proved reserves of 82.1 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of $5.58 per BOE of estimated proved reserves. Proved developed reserve quantities represented 36% of the total proved reserves acquired. The average daily production from the properties was 4.6 MBOE/d as of the acquisition effective date. We funded the cash portion of the purchase price with the net proceeds from a public offering of common stock and a private placement of 7% Senior Subordinated Notes due 2014. We expect to incur $656.0 million in future development costs related to these properties.

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Postle Properties. On August 4, 2005, we acquired the operated interest in producing oil and gas fields located in the Oklahoma Panhandle. The purchase price was $343.0 million for estimated proved reserves of 40.3 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of $8.52 per BOE of estimated proved reserves. The average daily production from the properties was 4.2 MBOE/d as of the acquisition effective date. Proved developed reserve quantities represented 57% of the total proved reserves acquired. We funded the acquisition through borrowings under Whiting Oil and Gas Corporation s credit agreement. We expect to incur $302.6 million in future development costs related to these properties.

Limited Partnership Interests. On June 23, 2005, we acquired all of the limited partnership interests in three institutional partnerships managed by our wholly-owned subsidiary Whiting Programs, Inc. The partnership properties were located in Louisiana, Texas, Arkansas, Oklahoma and Wyoming. The purchase price was $30.5 million for estimated proved reserves of 2.9 MMBOE as of the acquisition effective date of January 1, 2005, resulting in a cost of $10.52 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 0.7 MBOE/d as of the acquisition effective date. We funded the acquisition with cash on hand.

Green River Basin. On March 31, 2005, we acquired operated interests in five producing gas fields in the Green River Basin of Wyoming. The purchase price was $65.0 million for estimated proved reserves of 8.4 MMBOE as of the acquisition effective date of March 1, 2005, resulting in a cost of $7.74 per BOE of estimated proved reserves. Proved developed reserve quantities represented 68% of the total proved reserves acquired. The average daily production from the properties was 1.1 MBOE/d as of the acquisition effective date. We funded the acquisition though borrowings under Whiting Oil and Gas Corporation s credit agreement and with cash on hand.

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Results of Operations

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

	Year Ended December 31, 2006	2005	2004
Net production:			
Oil (MMbbls)	9.8	7.0	3.7
Natural gas (Bcf)	32.1	30.3	25.1
Total production (MMBOE)	15.2	12.1	7.9
Net sales (in millions):			
Oil (1)	$ 561.2	$ 360.4	$ 141.7
Natural gas (1)	$ 211.9	$ 212.8	$ 139.4
Total oil and natural gas sales	$ 773.1	$ 573.2	$ 281.1
Average sales prices:			
Oil (per Bbl)	$ 57.27	$ 51.26	$ 38.72
Effect of oil hedges on average price (per Bbl)	$ (0.95)	$ (2.72)	$ (1.33)
Oil net of hedging (per Bbl)	$ 56.32	$ 48.54	$ 37.39
Average NYMEX price	$ 66.25	$ 56.61	$ 41.43
Natural gas (per Mcf)	$ 6.59	$ 7.03	$ 5.56
Effect of natural gas hedges on average price (per Mcf)	$ 0.06	$ (0.47)	$
Natural gas net of hedging (per Mcf)	$ 6.65	$ 6.56	$ 5.56
Average NYMEX price	$ 7.23	$ 8.64	$ 6.14
Cost and expense (per BOE):			
Lease operating expenses	$ 12.12	$ 9.24	$ 6.91
Production taxes	$ 3.11	$ 2.99	$ 2.14
Depreciation, depletion and amortization expense	$ 10.74	$ 8.08	$ 6.89
General and administrative expenses	$ 2.49	$ 2.53	$ 2.45

(1) Before consideration of hedging transactions.

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

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $199.9 million to $773.1 million in 2006 compared to 2005. Sales are a function of sales volumes and average sales prices. Our oil sales volumes increased 39% and our gas sales volumes increased 6% between periods. The volume increases resulted from acquisitions completed in 2005 and 2006 and successful drilling activities over the past year, which produced new sales volumes that more than offset natural production decline. Our average price for oil increased 12% and our average price for natural gas decreased 6% between periods.

Loss on Oil and Natural Gas Hedging Activities. We hedged 54% of our oil volumes during 2006, incurring a hedging loss of $9.4 million, and 58% of our oil volumes during 2005, incurring a hedging loss of $19.1 million. We hedged 59% of our gas volumes during 2006 incurring a hedging gain of $1.9 million, and 60% of our gas volumes during 2005, incurring a hedging loss of $14.3 million. See Item 7A, Qualitative and Quantitative Disclosures About

Market Risk for a list of our outstanding oil and gas hedges as of January 1, 2007.

Gain on Sale of Oil and Gas Properties. 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. 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.

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Lease Operating Expenses. Our lease operating expense increased $72.1 million to $183.6 million in 2006 compared to 2005. The increase resulted primarily from costs associated with new property acquisitions during 2005 and 2006 and successful drilling activities over the past year. Our lease operating expense as a percentage of oil and gas sales increased from 19% during 2005 to 24% during 2006. Our lease operating expenses per BOE increased from $9.24 during 2005 to $12.12 during 2006. The increase of 31% on a BOE basis was primarily caused by inflation in the cost of oil field goods and services, a high level of workover activity on recently acquired properties, increased costs related to tertiary recovery projects, a change in labor billing practices and higher energy costs. Oil field goods and services increased due to a higher demand in the industry. Workovers amounted to $8.9 million in 2006, as compared to $3.9 million of workover activity during 2005. During the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. The changes resulted in lower general and administrative expense to us 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 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 2006 and 2005 were 6.1% and 6.3%, respectively, of oil and gas sales. The 2006 rate was lower than the 2005 rate due to the change in property mix associated with recent acquisitions.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (DD&A) increased $65.2 million to $162.8 million during 2006 as compared to $97.6 million for 2005. The increase resulted from higher production volumes in 2006 and an increase in our DD&A rate. On a BOE basis, our DD&A rate increased from $8.08 during 2005 to $10.74 in 2006. The primary factors causing this rate increase were higher drilling expenditures, downward oil and gas reserve revisions, and an increased level of expenditures to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields where the development of undeveloped reserves does not increase existing proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. Also contributing to our higher DD&A rate was the association of all 2005 property acquisition costs with proved reserves and none with unproved reserves, thereby including all such costs in our DD&A rate immediately when incurred. Changes to the pricing environment can also positively impact our DD&A rate. Price increases allow for longer economic production lives and corresponding increased reserve volumes and, as a result, lower depletion rates. Price decreases have the opposite effect. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2006	**2005**
Depletion and amortization	$ 157,868	$ 93,818
Depreciation	2,675	1,457
Accretion of asset retirement obligations	2,288	2,364
Total	$ 162,831	$ 97,639

Exploration and Impairment Costs. Our exploration and impairment costs increased $17.8 million to $34.5 million in 2006 compared to 2005. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2006	**2005**
Exploration	$ 30,079	$ 14,665
Impairment	4,455	2,034
Total	$ 34,534	$ 16,699

Higher exploration costs resulted from three exploratory dry holes drilled in the Rocky Mountains region, one exploratory dry hole drilled in the Gulf Coast region and one exploratory dry hole drilled in the Mid-Continent region in 2006, totaling $7.2 million. In 2005, we drilled a total of seven exploratory dry holes, totaling $4.0 million. We incurred $12.2 million in geological and geophysical expenses during 2006, up $7.4 million from 2005. We also hired additional exploration personnel to support the increased drilling budget from $223.6 million in 2005 to $455.0 million in 2006 resulting in an additional $4.0 million of exploration expense. The impairment charge in 2006 related to $3.7 million of amortized leasehold costs associated with individually insignificant unproved properties and $0.8 million of proved properties. The impairment charge in 2005 related to unrecoverable costs associated with our investment in the Cherokee Basin in Kansas.

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

	Year Ended December 31,	
	2006	**2005**
General and administrative expenses	$ 60,972	$ 42,594
Reimbursements and allocations	(23,164)	(11,987)
General and administrative expenses, net	$ 37,808	$ 30,607

General and administrative expenses before reimbursements and allocations increased $18.4 million to $61.0 million during 2006. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $13.6 million and an increase in the current year accrual for cash payments under our Production Participation Plan of $3.6 million. Personnel salary expenses were higher in 2006 due to an increase in our employee base resulting from our continued growth. The increased cost of the Production Participation Plan was caused primarily by higher 2006 production volumes and higher average sales prices on crude oil between years. The increase in reimbursements and allocations in 2006 was caused by increased salary expenses and a higher number of field workers and operated properties, due to recent acquisitions and drilling activities during 2006. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. The changes resulted in lower general and administrative expense to us and higher amounts of lease operating expense being allocated to us and charged to our joint interest owners on properties we operate. As a percentage of oil and gas sales, our general and administrative expenses remained consistent at 5%.

Change in Production Participation Plan Liability. For the year ended December 31, 2006, this non-cash expense decreased $3.6 million to $6.2 million. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2007 under our Production Participation Plan (Plan). Although payments take place over the life of oil and gas properties contributed to the Plan, which for some properties is over 20 years, we must expense the present value of estimated future payments over the Plan s five year vesting period. The 2006 expense primarily reflects changes to future cash flow estimates and related Plan liability, due to the effect of a sustained higher price environment and recent acquisitions, as well as employees continued vesting in the Plan. 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.

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

	Year Ended December 31,	
	2006	2005
Credit Agreement	$ 21,478	$ 9,997
Senior Subordinated Notes	44,530	25,109
Amortization of debt issue costs and debt discount	5,208	4,076
Accretion of tax sharing liability	2,016	2,725
Other	813	138
Capitalized interest	(556)	
Total interest expense	$ 73,489	$ 42,045

The increase in interest expense and amortization of debt issue costs and debt discount were mainly due to the April 2005 issuance of $220.0 million 7.25% Senior Subordinated Notes due 2013, the October 2005 issuance of $250.0 million 7% Senior Subordinated Notes due 2014, and additional borrowings outstanding in 2006 under our credit agreement. We also experienced higher weighted average interest rates on our debt during 2007.

Our weighted average debt outstanding during 2006 was $945.3 million versus $553.0 million during 2005. Our weighted average effective cash interest rate was 7.0% during 2006 versus 6.4% during 2005. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discounts and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 7.5% during 2006 versus 7.2% during 2005.

Income Tax Expense. Income tax expense totaled $76.9 million for 2006 and $74.2 million for 2005. Our effective income tax rate decreased from 37.8% for 2005 to 33.0% for 2006 primarily due to the recognition in 2006 of a $4.2 million deferred tax benefit for 2005 enhanced oil recovery (EOR) tax credits, a $3.3 million benefit relating to an adjustment of our effective rate to our 2005 state returns as filed, and deferred tax benefits of $1.3 million as a result of recently enacted state tax legislation.

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 recent high oil prices, the EOR credit was phased-out for 2006.

The current portion of income tax expense was $12.3 million for 2006 compared to $8.5 million in 2005. In 2006, we reported a tax loss on our 2005 federal return as filed, primarily due to intangible drilling deductions allowed, which resulted in a federal tax refund of $4.7 million.

Net Income. Net income increased from $121.9 million in 2005 to $156.4 million for 2006. The primary reasons for this increase included a 26% increase in equivalent volumes sold, a 14% increase in oil and gas prices net of hedging between periods, certain income tax benefits recognized during 2006 and a gain on sale of oil and gas properties. These increases were partially offset by higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative and interest expenses in 2006 resulting from our continued growth.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $292.2 million to $573.2 million in 2005. Sales are a function of sales volumes and average sales prices. Our sales volumes increased 54% between periods on a BOE basis. The volume increase resulted primarily from acquisition activities and successful drilling activities over the past year that produced new sales volumes that more than offset natural field production decline.

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Our production volumes for 2005 were slightly less than anticipated due in part to delays in rig availability that caused delays in our development drilling program and temporary pipeline shut downs and workover activity in the first quarter of 2005. Hurricanes Katrina and Rita caused only minor reductions to our 2005 sales volumes, in that only 16,700 BOE of total estimated production was lost during 2005 due to the hurricanes. Our average price for crude oil increased 32% between periods and our average price for natural gas sales increased 26%.

Loss on Oil and Natural Gas Hedging Activities. We hedged 58% of our oil volumes during 2005, incurring a hedging loss of $19.1 million, and 50% of our oil volumes during 2004, incurring a hedging loss of $4.9 million. We hedged 60% of our gas volumes during 2005, incurring a hedging loss of $14.3 million, and 32% of our gas volumes during 2004, incurring no hedging gain or loss.

Gain on Sale of Marketable Securities. During 2004, we sold all of our holdings in Delta Petroleum, Inc., which trades publicly under the symbol DPTR . We realized gross proceeds of $5.4 million and recognized a gain on sale of $4.8 million. During 2005, we had no investments in marketable securities.

Gain on Sale of Oil and Gas Properties. During 2004, we sold certain undeveloped acreage in Wyoming. No value had been assigned to the acreage when we acquired it over five years ago. As a result, the recognized gain on sale was equal to the gross proceeds of $1.0 million.

Lease Operating Expenses. Our lease operating expense increased $57.3 million to $111.6 million in 2005 compared to 2004. The increase resulted primarily from costs associated with new property acquisitions over the past year. Our lease operating expenses per BOE increased from $6.91 during 2004 to $9.24 during 2005. The increase of 34% was mainly caused by higher costs for electric power and increases in the cost of oil field goods and services due to higher demand in the industry. In addition, our lease operating expenses increased on a BOE basis due to the newly acquired Postle and North Ward Estes properties, which had fourth quarter combined operating costs of $12.72 per BOE relating to the secondary and tertiary recovery projects underway on those fields.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed by the various taxing jurisdictions. Our production taxes for 2005 and 2004 were 6.3% and 6.0%, respectively, of oil and gas sales. The increase in tax rates between periods was related to product price increases that eliminate certain exemptions and move us into higher tax tiers in our various tax jurisdictions, which effect was partially offset by lower production taxes on our properties newly acquired in 2005.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (DD&A) increased $43.6 million to $97.6 million during 2005 as compared to $54.0 million for 2004. The increase resulted from increased production due to our recent acquisitions and an increase in our DD&A rate. On a BOE basis, our DD&A rate increased from $6.89 during 2004 to $8.08 in 2005. The primary factors causing this rate increase were higher drilling expenditures, downward oil and gas reserve revisions, and an increased level of expenditures to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields where the development of undeveloped reserves does not increase existing proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. Changes to the pricing environment can also positively impact our DD&A rate. Price increases allow for longer economic production lives and corresponding increased reserve volumes and, as a result, lower depletion rates. Price decreases have the opposite effect. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31, 2005	2004
Depletion	$ 93,818	$ 51,424
Depreciation	1,457	832
Accretion of asset retirement obligations	2,364	1,754
Total	$ 97,639	$ 54,010

Exploration and Impairment Costs. Our exploration and impairment costs increased $10.4 million to $16.7 million in 2005 compared to 2004. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31, 2005	2004
Exploration	$ 14,665	$ 4,177
Impairment	2,034	2,152
Total	$ 16,699	$ 6,329

Higher exploratory costs resulted from seven exploratory dry holes drilled during 2005 totaling $4.0 million, as compared to two exploratory dry holes in 2004 totaling $0.6 million. We also hired additional geological and geophysical personnel to support the increased drilling budget from $83.8 million in 2004 to $223.6 million in 2005. The impairment charge in 2005 relates primarily to unrecoverable costs associated with our investment in the Cherokee Basin in Kansas. The impairment charge in 2004 was for the write down of cost associated with the High Island field located off the coast of Texas.

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

	Year Ended December 31, 2005	2004
General and administrative expenses	$ 42,594	$ 25,992
Reimbursements	(11,987)	(6,768)
General and administrative expenses, net	$ 30,607	$ 19,224

General and administrative expenses before reimbursements increased $16.6 million to $42.6 million during 2005 compared to $26.0 million during 2004. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $9.2 million, an increase in the current year cash payment under our Production Participation Plan of $3.3 million and the amortization of restricted stock compensation of $2.9 million. Personnel salary expenses were higher in 2005 due primarily to an increase in our employee base resulting from our continued growth. The increased cost of the Production Participation Plan was caused primarily by higher 2005 production volumes and higher average sales prices between years. Restricted stock compensation increased due to the additional issuance of restricted stock in 2005 and due to the layering impact of a multiple year vesting schedule. The increase in reimbursements in 2005 was caused by a higher number of operated properties due to acquisitions and drilling activities during the last half of 2004 and 2005. Our net general and administrative expenses on a BOE basis increased 3% between periods from $2.45 to $2.53. As a percentage of oil and gas sales, our general and administrative expenses decreased from 7% during 2004 to 5% during 2005, as general and administrative costs increased at a slower rate than oil and gas sales prices.

Change in Production Participation Plan Liability. For the year ended December 31, 2005, this non-cash expense increased $8.0 million to $9.7 million from $1.7 million during 2004. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2006 under our Production Participation Plan (Plan). Although payments take place over the life of oil and gas properties contributed to the Plan, which for some properties is over 20 years, we must expense the present value of estimated future payments over the Plan s five year vesting period. The increase in expense primarily reflects changes to future cash flow estimates due to the effect of a sustained higher price environment and acquisitions during 2005. 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.

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

	Year Ended December 31,	
	2005	**2004**
Credit Agreement	$ 9,997	$ 5,893
Senior Subordinated Notes	25,109	5,957
Amortization of debt issue costs and debt discount	4,076	1,666
Accretion of tax sharing liability	2,725	2,390
Other	138	150
Capitalized interest		(200)
Total interest expense	$ 42,045	$ 15,856

The increase in interest expense was mainly due to the May 2004 issuance of $150.0 million 7.25% Senior Subordinated Notes due 2012, the April 2005 issuance of $220.0 million 7.25% Senior Subordinated Notes due 2013, the October 2005 issuance of $250.0 million 7% Senior Subordinated Notes due 2014, and additional borrowings outstanding in 2005 under our credit agreement. The additional amortization of debt issue costs and debt discount in 2005 was due to the greater number of days that each instrument s capitalized issue costs and debt discounts were outstanding versus the prior year.

Our weighted average debt outstanding during 2005 was $553.0 million versus $257.8 million during 2004. Our weighted average effective cash interest rate was 6.4% during 2005 versus 4.7% 2004. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discounts and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 7.2% during 2005 versus 5.5% during 2004.

Income Tax Expense. Income tax expense totaled $74.2 million for 2005 and $44.0 million for 2004, resulting in effective income tax rates of 37.8% and 38.6%, respectively. We were able to defer the majority of our cash income tax obligations primarily due to the level of intangible drilling deductions allowed in each year. We reported current income tax expense of $8.5 million in 2005 or 11.5% of the tax provision, as compared to $3.9 million or 8.8% of the tax provision in 2004. The lower rate of current income tax expense in 2004 was mainly due to the use of our 2003 net operating loss carryforward in 2004.

Net Income. Net income increased from $70.0 million during 2004 to $121.9 million during 2005. The primary reasons for this increase included 27% higher oil and gas prices net of hedging between periods and a 54% increase in equivalent volumes sold, which were partially offset by higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative, Production Participation Plan, interest expenses, and income taxes in 2005 resulting from our continued growth.

Liquidity and Capital Resources

Overview. At December 31, 2005, our debt to total capitalization ratio was 46.4%, we had $10.4 million of cash on hand and $997.9 million of stockholders equity. At December 31, 2006, our debt to total capitalization ratio was 45.4%, we had $10.4 million of cash on hand and $1,186.7 million of stockholders equity. In 2006, we generated $411.2 million from operating activities, an increase of $81.0 million over 2005. Cash provided by operating activities increased primarily because of higher production from our recent acquisitions, successful drilling activities and higher average sales prices for crude oil, and was partially offset by higher operating costs. We also generated $116.4 million from financing activities primarily consisting of $120.0 million in net borrowings against our credit agreement. Cash on hand and cash flows from operating and financing activities, as well proceeds of $24.4 million from the sale of oil and gas properties, were primarily used to finance $464.4 million of drilling and development capital expenditures paid in 2006 and $87.6 million of cash acquisition capital expenditures to acquire the Michigan Properties, the central Utah Hingeline unproved acreage, tubular goods, other unproved property leaseholds and an oil transportation pipeline. The chart below details our drilling and development capital expenditures incurred by region during 2006 (in thousands):

	Drilling Capex	% of Total
Permian Basin	$ 186,533	41%
Rocky Mountains	131,704	29%
Mid-Continent	88,008	19%
Gulf Coast	41,256	9%
Michigan	7,489	2%
Total drilling and development capital expenditures incurred	454,990	100%
Decrease in accrued capital expenditures	9,417	
Total drilling and development capital expenditures paid	$ 464,407	

We continually evaluate our capital needs and compare them to our capital resources. Our 2007 budgeted capital expenditures for the further development of our property base are $350.0 million, a decrease from the $455.0 million incurred on capitalized drilling and development during 2006. Although we have no specific budget for property acquisitions in 2007, we will continue to seek property acquisition opportunities that complement our existing core property base. We expect to fund our 2007 development expenditures from internally generated cash flow and cash on hand. We believe that should attractive acquisition opportunities arise or development expenditures exceed $350.0 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 securities or equity, or agreements with industry partners. Our level of capital 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.

Credit Agreement. Whiting Oil and Gas Corporation has a $1.2 billion credit agreement with a syndicate of banks that, as of December 31, 2006, had a borrowing base of $875.0 million with $380.0 million outstanding, leaving $495.0 million of available borrowing capacity. The borrowing base under the credit agreement is determined at the discretion of the 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 Gas Corporation may, throughout the five-year term of the credit agreement, borrow, repay and re-borrow up to the borrowing base in effect from time to time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas Corporation or other designated subsidiaries of ours from time to time in an aggregate amount not to exceed $50.0 million. As of December 31, 2006, letters of credit totaling $0.3 million were outstanding under the credit agreement.

Interest accrues, at Whiting Oil and Gas Corporation s option, at either (1) 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 (2) 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. Whiting Oil and Gas Corporation has consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. 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, 2006, the effective weighted average interest rate on the entire outstanding principal balance under the credit agreement was 6.5%.

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 and requires us to maintain a debt to EBITDAX (as defined in the credit agreement) ratio of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement) 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 Corporation and our wholly owned subsidiary, Equity Oil Company, to make any dividends, distributions or other payments to us. 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, 2006. The credit agreement is secured by a first lien on all of Whiting Oil and Gas Corporation s properties included in the borrowing base for the credit agreement. We and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement. We have pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for our guarantee, and Equity Oil Company has mortgaged all of its properties included in the borrowing base for the credit agreement as security for its guarantee.

Senior Subordinated Notes. In October 2005, we issued $250.0 million of 7% Senior Subordinated Notes due 2014 at par.

In April 2005, we issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. The Notes were issued at 98.507% of par and the associated discount is being amortized to interest expense over the term of the notes.

In May 2004, we issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. The Notes were issued at 99.26% of par and the associated discount is being amortized to interest expense over the term of the 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 Corporation s credit agreement. The indentures governing the notes contain restrictive covenants that may limit our and our subsidiaries ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, make investments, incur additional indebtedness 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. In addition, Whiting Oil and Gas Corporation s credit agreement restricts the ability of our subsidiaries to make certain payments, including principal on the notes, to us. We were in compliance with these covenants as of December 31, 2006. Three of our 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. In May 2006, we filed a universal shelf registration statement with the SEC 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. 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.

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Tax Sharing Liability. In connection with our initial public offering in November 2003, we entered into a tax separation and indemnification agreement with our former parent, Alliant Energy Corporation (Alliant Energy). Pursuant to this agreement, we and Alliant Energy made a tax election with the effect that the tax bases of the assets of Whiting Oil and Gas Corporation and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. We have adjusted deferred taxes on our balance sheet to reflect the new tax bases of our assets. These additional 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. Such tax benefits will generally be calculated by comparing our actual taxes to the taxes that would have been owed by us had the increase in bases not occurred. 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. We have estimated that total payments to Alliant will approximate $38.6 million on an undiscounted basis, with a present value of $25.7 million. During 2006, we made a payment of $3.7 million under this agreement. Our estimate of payments to be made under this agreement of $3.6 million in 2007 is reflected as a current liability at December 31, 2006.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The following table summarizes our material obligations and commitments as of December 31, 2006 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include Production Participation Plan liabilities since we cannot determine with accuracy the timing of future payments (in thousands):

		Payments due by period			
Contractual Obligations	**Total**	**Less than 1 year**	**2-3 years**	**4-5 years**	**More than 5 years**
Long-term debt (a)	$ 995,396	$	$	$ 380,000	$ 615,396
Cash interest expense on debt (b)	389,107	69,270	138,540	105,764	75,533
Asset retirement obligation (c)	37,534	552	1,089	2,558	33,335
Tax sharing liability (d)	27,172	3,565	5,988	5,044	12,575
Derivative contract liability fair value (e)	9,336	4,088	5,248		
Purchase obligations (f)	308,877	17,479	100,298	103,256	87,844
Drilling rig contracts (g)	47,472	17,334	25,314	4,824	
Operating leases (h)	7,184	1,742	3,531	1,870	41
Total	$ 1,822,078	$ 114,030	$ 280,008	$ 603,316	$ 824,724

(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 7.7% 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 a fixed interest rate of 6.5%.

(c) Asset retirement obligations represent the estimated present value of amounts expected to be incurred to plug, abandon and remediate oil and gas properties.

(d) Amounts shown are the estimated payments due based on projected future income tax benefits from the increase in tax bases described under Tax Sharing Liability above.

(e) We have entered into derivative contracts, primarily costless collars, to hedge our exposure to crude oil and natural gas price fluctuations. As of December 31, 2006, the forward price curves for oil and 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 risk.

(f) We entered into two take-or-pay purchase agreements, one agreement in July 2005 for 9.5 years and one agreement in March 2006 for 8 years, whereby we have committed to buy certain volumes of CO_2 for a fixed fee, subject to annual escalation, for use in enhanced recovery projects in our Postle field in Texas County, Oklahoma and our North Ward Estes field in Ward County, 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 entered into three separate three-year agreements in 2005 for drilling rigs, a two-year agreement in February 2006 for a workover rig, and a three-year agreement in September 2006 for an additional drilling rig, all operating in the Rocky Mountains region. As of December 31, 2006, early termination of these contracts would have required maximum penalties of $32.7 million. No other drilling rigs working for us are currently under long-term contracts or contracts which 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.

(h) We lease 87,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2010, and an additional 26,500 square feet of office space in Midland, Texas through February 15, 2012.

Based on current oil and 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.

Price-Sharing Agreement. As part of a 2002 purchase transaction, we agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2007 increased to 50% of the actual price received in excess of $20.97 per barrel. As of December 31, 2006, approximately 40,300 net barrels of crude oil per month (5% of December 2006 net crude oil production) are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. During the years 2006, 2005 and 2004, we paid $9.4 million, $7.6 million and $4.8 million, respectively, under this agreement. As of December 31, 2006, we have accrued an additional $0.6 million as a current payable.

New Accounting Policies

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), *Share-Based Payment* (SFAS 123R). The adoption of SFAS 123R had a minimal impact on income before income taxes and net income, and had no effect on basic or diluted earnings per share, for the year ended December 31, 2006, as presented in the our consolidated statements of income. This Statement is a revision of SFAS No. 123, *Accounting for*

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Stock-Based Compensation (SFAS 123), and supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and its related implementation guidance. SFAS 123R requires a company to measure the grant date fair value of equity awards given to employees in exchange for services and recognize that cost, less estimated forfeitures, over the period that such services are performed. Prior to adopting SFAS 123R, the Company accounted for stock-based compensation under SFAS 123, whereby the Company s policy was to recognize actual forfeitures of restricted stock only when they occurred rather than estimate them at the grant date and subsequently true-up estimated forfeitures to actuals. SFAS 123R requires companies to include forfeitures as part of the grant date estimate of compensation cost. We adopted SFAS 123R on January 1, 2006 using the modified prospective transition method. In accordance with the modified prospective method, prior period results have not been restated.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). The adoption of SAB 108 did not have a material impact on our consolidated financial position or results of operations. SAB 108 provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 is effective for fiscal years ending on or after November 15, 2006 and provides for a one-time transitional cumulative effect adjustment to beginning retained earnings as of January 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108.

New Accounting Pronouncements

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an interpretation of Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (FIN 48). We are currently evaluating the effect that the adoption of FIN 48 will have on our financial statements and have not yet determined whether or not the adoption will have a material impact on its financial position or results of operations. The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006.

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* (SFAS 157). The adoption of SFAS 157 is not expected to have a material impact on our consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop the measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years.

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. Our significant accounting policies are 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

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financial position and results of operations and which require the application of significant judgment by our management.

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 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 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 Ryder Scott Company, Cawley, Gillespie & Associates, Inc., and R.A. Lenser & Associates, Inc., each independent petroleum engineers, and our engineering staff. The independent petroleum engineers evaluated 100% of our estimated proved reserve quantities and their related future net cash flows as of December 31, 2006. 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 the 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. This decline may result from lower market 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 net 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 (ARO) consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. 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 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.

Production Participation Plan. We have a Production Participation Plan (Plan) in which all eligible 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 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 on our consolidated balance sheets. This obligation is based on cash flows during the preceding 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 on the consolidated balance sheets. This liability is derived primarily from reserve report estimates discounted at 15%, 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 five years. Variances between estimates used to calculate liabilities related to the Production Participation Plan and actual sales, cost 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, 2006 would have decreased net income before taxes by $3.9 million in 2006.

Derivative Instruments and Hedging Activity. We periodically enter into commodity derivative contracts to manage our exposure to oil and gas price volatility. We use hedging to reduce price volatility, 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 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 required to be recorded on the consolidated balance sheet at fair value. Changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the 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 the 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. We currently do not have any derivative contracts in place that do not qualify as cash flow hedges.

We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently evaluated internally using established index prices and readily available market data. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. 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 hedges did 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. 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 under accounting standards, 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 gas prices).

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 using the purchase method, which is the only method permitted under SFAS No. 141, *Business Combinations,* and involves the use of significant judgment.

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

Effects of Inflation and Pricing

We experienced increased costs during 2006, 2005 and 2004 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 gas increase, so do all associated costs. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans 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, continued high prices for oil and gas could result in increases in the costs of materials, services and personnel.

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 2006 production, our income before income taxes for 2006 would have moved up or down $3.2 million for every $0.10 change in gas prices and $9.8 million for each $1.00 change in oil prices.

We periodically enter into derivative contracts to manage our exposure to oil and 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 where accounting treatment allows the aggregate change in fair market value to be recorded as accumulated other comprehensive income (loss). Recognition in the consolidated statements of income occurs in the period of contract settlement.

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Our outstanding hedges as of January 1, 2007 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)	NYMEX Floor/Ceiling
Crude Oil	01/2007 to 03/2007	125,000	$45.00/$81.00
Crude Oil	01/2007 to 03/2007	215,000	$50.00/$70.90
Crude Oil	01/2007 to 03/2007	110,000	$50.00/$73.15
Crude Oil	04/2007 to 06/2007	110,000	$50.00/$72.00
Crude Oil	04/2007 to 06/2007	300,000	$50.00/$78.50
Crude Oil	07/2007 to 09/2007	110,000	$50.00/$70.90
Crude Oil	07/2007 to 09/2007	300,000	$50.00/$77.55
Crude Oil	10/2007 to 12/2007	110,000	$49.00/$71.50
Crude Oil	10/2007 to 12/2007	300,000	$50.00/$76.50
Crude Oil	01/2008 to 03/2008	110,000	$49.00/$70.65
Crude Oil	04/2008 to 06/2008	110,000	$48.00/$71.60
Crude Oil	07/2008 to 09/2008	110,000	$48.00/$70.85
Crude Oil	10/2008 to 12/2008	110,000	$48.00/$70.20
Natural Gas	01/2007 to 03/2007	600,000	$6.00/$15.20
Natural Gas	01/2007 to 03/2007	1,000,000	$6.00/$15.52

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 beyond the ceiling. For the 2007 crude oil contracts listed above, a hypothetical $1.00 change in the NYMEX price would cause a change in the gain (loss) on hedging activities in 2007 of $5.0 million. For the 2007 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 the gain (loss) on hedging activities in 2007 of $0.5 million.

In a previous acquisition, we also assumed certain fixed price marketing contracts directly with end users for a portion of the natural gas we produce in Michigan. All of those contracts have built-in pricing escalators of 4% per year. Our outstanding fixed price marketing contracts at January 1, 2007 are summarized below:

Commodity	Period Remaining	Monthly Volume (MMBtu)	2007 Price Per MMBtu
Natural Gas	01/2007 to 12/2011	51,000	$4.75
Natural Gas	01/2007 to 12/2012	60,000	$4.21

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. At December 31, 2006, our outstanding principal balance under our credit agreement was $380.0 million and the weighted average interest rate on the outstanding principal balance was fixed at 6.5% through June 2007. At December 31, 2006, the carrying amount approximated fair market value. Assuming a constant debt level of $380.0 million, the cash flow impact for 2006 resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $1.9 million.

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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 at December 31, 2006 was 5.4%. As of December 31, 2006, we have recorded a long term liability of $1.5 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding decrease in the carrying value of the Senior Subordinated Notes.

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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, 2006 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, 2006, our internal control over financial reporting was effective based on those criteria.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on management s assessment of our internal control over financial reporting. That attestation report is set forth immediately prior to the report of Deloitte & Touche LLP on the financial statements included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management s assessment, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting, that Whiting Petroleum Corporation and subsidiaries (the Company) maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated February 26, 2007 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP
Denver, Colorado
February 26, 2007

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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, 2006 and 2005, 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, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Whiting Petroleum Corporation and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Denver, Colorado
February 26, 2007

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2006	December 31, 2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 10,372	$ 10,382
Accounts receivable trade, net	97,831	101,066
Deferred income taxes	3,025	15,121
Prepaid expenses and other	10,484	5,595
Total current assets	121,712	132,164
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	2,828,282	2,353,372
Unproved properties	55,297	21,671
Other property and equipment	44,902	26,235
Total property and equipment	2,928,481	2,401,278
Less accumulated depreciation, depletion and amortization	(495,820)	(338,420)
Total property and equipment, net	2,432,661	2,062,858
DEBT ISSUANCE COSTS	19,352	23,660
OTHER LONG-TERM ASSETS	11,678	16,514
TOTAL	$ 2,585,403	$ 2,235,196

See notes to consolidated financial statements. (Continued)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share data)

	December 31, 2006	December 31, 2005
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 21,077	$ 13,159
Accrued liabilities	58,504	54,927
Accrued interest	9,124	11,894
Oil and gas sales payable	19,064	21,154
Accrued employee compensation and benefits	17,800	15,351
Production taxes payable	9,820	13,259
Current portion of tax sharing liability	3,565	4,254
Current portion of derivative liability	4,088	34,569
Total current liabilities	143,042	168,567
NON-CURRENT LIABILITIES:		
Long-term debt	995,396	875,098
Asset retirement obligations	36,982	32,193
Production Participation Plan liability	25,443	19,287
Tax sharing liability	23,607	24,576
Deferred income taxes	165,031	91,577
Long-term derivative liability	5,248	21,817
Other long-term liabilities	3,984	4,219
Total non-current liabilities	1,255,691	1,068,767
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY:		
Common stock, $.001 par value; 75,000,000 shares authorized, 36,947,681 and 36,841,823 shares issued and outstanding as of December 31, 2006 and 2005, respectively	37	37
Additional paid-in capital	754,788	753,093
Accumulated other comprehensive loss	(5,902)	(34,620)
Deferred compensation		(2,031)
Retained earnings	437,747	281,383
Total stockholders equity	1,186,670	997,862
TOTAL	$ 2,585,403	$ 2,235,196

See notes to consolidated financial statements. (Concluded)

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share data)

	Year Ended December 31, 2006	2005	2004
REVENUES AND OTHER INCOME:			
Oil and natural gas sales	$ 773,120	$ 573,246	$ 281,057
Loss on oil and natural gas hedging activities	(7,501)	(33,377)	(4,875)
Gain on sale of oil and gas properties	12,092		1,000
Gain on sale of marketable securities			4,835
Interest income and other	1,116	579	123
Total revenues and other income	778,827	540,448	282,140
COSTS AND EXPENSES:			
Lease operating	183,642	111,560	54,212
Production taxes	47,095	36,092	16,793
Depreciation, depletion and amortization	162,831	97,639	54,010
Exploration and impairment	34,534	16,699	6,329
General and administrative	37,808	30,607	19,224
Change in Production Participation Plan liability	6,156	9,708	1,711
Interest expense	73,489	42,045	15,856
Total costs and expenses	545,555	344,350	168,135
INCOME BEFORE INCOME TAXES	233,272	196,098	114,005
INCOME TAX EXPENSE:			
Current	12,346	8,514	3,882
Deferred	64,562	65,662	40,077
Total income tax expense	76,908	74,176	43,959
NET INCOME	$ 156,364	$ 121,922	$ 70,046
NET INCOME PER COMMON SHARE, BASIC	$ 4.26	$ 3.89	$ 3.38
NET INCOME PER COMMON SHARE, DILUTED	$ 4.25	$ 3.88	$ 3.38
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	36,736	31,356	20,735

WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	36,826	31,449	20,768

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 156,364	$ 121,922	$ 70,046
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	162,831	97,639	54,010
Deferred income taxes	64,562	65,662	40,077
Amortization of debt issuance costs and debt discount	5,208	4,076	1,466
Accretion of tax sharing agreement	2,016	2,725	2,390
Stock-based compensation	3,969	2,861	580
Gain on sale of oil and gas properties	(12,092)		(1,000)
Gain on sale of marketable securities			(4,835)
Impairments of undeveloped leaseholds and oil and gas properties	4,455	2,034	2,152
Change in Production Participation Plan liability	6,156	9,708	1,711
Other non-current	2,653	373	(3,287)
Changes in current assets and liabilities:			
Accounts receivable trade	3,235	(35,012)	(34,633)
Prepaid expenses and other	(2,268)	(302)	(4,919)
Accounts payable and accrued liabilities	20,412	20,077	(650)
Accrued interest	(2,770)	9,844	628
Other liabilities	(3,522)	28,586	10,380
Net cash provided by operating activities	411,209	330,193	134,116
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash acquisition capital expenditures	(87,562)	(900,332)	(451,231)
Drilling and development capital expenditures	(464,407)	(196,163)	(79,376)
Proceeds from sale of marketable securities			5,420
Proceeds from sale of oil and gas properties	24,390		1,000
Equity Oil Company cash paid in excess of cash received			(256)
Acquisition of partnership interests, net of cash acquired of $26		(30,433)	
Net cash used in investing activities	(527,579)	(1,126,928)	(524,443)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayments to Alliant Energy Corporation	(3,675)	(8,242)	
Issuance of common stock		277,117	239,686
Issuance of 7.25% Senior Subordinated Notes due 2012			148,890
Issuance of 7.25% Senior Subordinated Notes due 2013		216,715	
Issuance of 7% Senior Subordinated Notes due 2014		250,000	

Issuance of long-term debt under credit agreement	325,000	395,000	445,800
Payments on long-term debt under credit agreement	(205,000)	(310,000)	(484,800)
Debt issuance costs	(253)	(15,370)	(11,174)
Tax effect from restricted stock vesting	288	237	
Net cash provided by financing activities	116,360	805,457	338,402
NET CHANGE IN CASH AND CASH EQUIVALENTS	(10)	8,722	(51,925)
CASH AND CASH EQUIVALENTS:			
Beginning of period	10,382	1,660	53,585
End of period	$ 10,372	$ 10,382	$ 1,660

See notes to consolidated financial statements. (Continued)

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	Year Ended December 31,		
	2006	2005	2004
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for income taxes	$ 12,063	$ 10,620	$ 4,479
Cash paid for interest	$ 69,591	$ 26,113	$ 11,222
NONCASH INVESTING ACTIVITIES:			
(Increase) decrease in accrued capital expenditures	$ 9,417	$ (27,432)	$ (4,412)
NONCASH FINANCING ACTIVITIES:			
Assumption of debt Equity Oil Company merger	$	$	$ 29,000
Issuance of common stock Equity Oil Company merger	$	$	$ 43,298
Issuance of common stock North Ward Estes acquisition	$	$ 17,175	$

See notes to consolidated financial statements. (Concluded)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME
(In thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Retained Earnings	Total Stockholders Equity	Comprehensive Income
BALANCES-January 1, 2004	18,750	$ 19	$ 170,367	$ (223)	$	$ 89,415	$ 259,578	
Net income						70,046	70,046	$ 70,046
Change in fair value of marketable securities for sale				3,741			3,741	3,741
Realized gain on marketable securities for sale				(4,835)			(4,835)	(4,835)
Change in derivative fair values, net of taxes				(2,701)			(2,701)	(2,701)
Realized loss on settled derivative contracts, net of related taxes				2,993			2,993	2,993
Issuance of stock Equity Oil Company	2,237	2	43,296				43,298	
Issuance of stock secondary offering	8,625	9	239,677				239,686	
Restricted stock issued	113		2,459		(2,459)			
Restricted stock forfeited	(7)		(164)		164			
Amortization of deferred compensation					580		580	
BALANCES-December 31, 2004	29,718	30	455,635	(1,025)	(1,715)	159,461	612,386	$ 69,244
Net income						121,922	121,922	121,922
Change in derivative fair values, net of taxes				(54,089)			(54,089)	(54,089)
Realized loss on settled derivative contracts, net of related taxes				20,494			20,494	20,494
Restricted stock issued	85		3,407		(3,407)			
Restricted stock forfeited	(9)		(230)		230			
Restricted stock used for tax withholdings	(6)		(241)				(241)	
Tax effect from restricted stock vesting			237				237	
Issuance of stock secondary offering	6,612	7	277,110				277,117	

Issuance of stock North Ward Estes acquisition	442		17,175				17,175	
Amortization of deferred compensation					2,861		2,861	
BALANCES-December 31, 2005	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				24,140			24,140	24,140
Realized loss on settled derivative contracts, net of related taxes				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

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations Whiting Petroleum Corporation (Whiting or the Company), 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.

Basis of Presentation of Consolidated Financial Statements The consolidated financial statements include the accounts of Whiting and its subsidiaries, all of which are wholly owned, together with its pro rata share of the assets, liabilities, revenue and expenses of limited partnerships in which Whiting was the sole general partner. In June 2005, Whiting increased its ownership interest to 100% in limited partnerships where it was the sole general partner and subsequently liquidated them. 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 earning and losses. All significant 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 and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and 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 receivable. 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 may have 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, 2006 and 2005, the Company had an allowance for doubtful accounts of $0.6 million and $0.4 million, respectively.

Inventories Materials and supplies inventories consist primarily of tubular goods and production equipment, stated at the lower of weighted-average cost or market. Materials and supplies are

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included in other property and equipment. Oil inventory in tanks is carried at the lower of the estimated cost to produce or market value and is included in prepaid expenses and other.

Marketable Securities Investments in marketable securities are classified as held-to-maturity, trading securities or available-for-sale. Trading and available-for-sale securities are recorded at estimated market value. Realized gains or losses for both classes of equity investments are determined on a specific identification basis and are included in income. Unrealized gains or losses of available-for-sale securities are excluded from earnings and reported in accumulated other comprehensive income (loss).

The Company owned equity investments in publicly traded securities classified as available-for-sale (included in other long term-assets) with an original cost to the Company of $0.6 million. During 2004, the Company sold all of its holdings for $5.4 million, realizing a gain on sale of $4.8 million.

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 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 exploration and development projects that require greater than six months to be readied for their intended use. During 2006, the Company capitalized $0.6 million of interest. During 2005 and 2004, capitalized interest costs were insignificant.

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 time, 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.

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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 and exploration costs.

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 that 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.

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

Debt Issuance Costs Debt issuance costs related to 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.

Asset Retirement Obligations and Environmental Costs Asset retirement obligations relate to future costs associated with 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 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 hedge future oil and gas production in order to mitigate the risk of market price fluctuations. The Company also enters into derivative contracts to mitigate the risk of interest rate fluctuations. The Company does not enter into derivative instruments for speculative or trading purposes.

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. Changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses on effective cash flow hedges to be deferred in accumulated other comprehensive income (loss) until the hedged transactions occur. Realized gains and losses on cash flow hedges are transferred from accumulated other comprehensive income (loss) and recognized in earnings as loss on oil and natural gas hedging activities . Realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Gains and losses from the change in the fair value of derivative instruments that do not qualify as a hedge or is not designated as a hedge, as well as the ineffective portion of hedge derivatives, if any, are reported in the consolidated statements of income. Derivative settlements are included in cash flows from operating activities.

The Company has formally documented 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. 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. If, during the derivative s term, the Company determines the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses on the effective portion of the derivative are reclassified to earnings when the underlying transaction occurs. If it is determined that the designated hedge transaction is not likely to occur, any unrealized gains or losses are recognized immediately in the consolidated statements of income as a derivative fair value gain or loss.

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, 2006, 2005 and 2004, the Company was in an (over) under produced imbalance position of (273,000) Mcf, (162,000) Mcf and 339,000 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 of 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 the benefit from the deferred tax asset will not be realized.

Earnings Per Share Basic net income per common share of stock is calculated by dividing net income by the weighted average number of common shares outstanding during each year. Diluted net income per common share of stock is calculated by dividing net income by the weighted average number of common shares and other dilutive securities outstanding. 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 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.

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 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 are reported on the balance sheet at fair market value.

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 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. During 2005, sales to Teppco Crude Oil LLC accounted for 10% of the Company s total oil and gas production revenue. In 2004, no single customer was responsible for generating 10% or more of the Company s total oil and gas sales.

Reclassifications Certain reclassifications have been made to prior years reported amounts in order to conform to the current year presentation. Such reclassifications had no impact on net income, stockholders equity or cash flows previously reported.

Change in Accounting Principle In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), *Share-Based Payment* (SFAS 123R). This Statement is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and its related implementation guidance. SFAS 123R requires a company to measure the grant date fair value of equity awards given to employees in exchange for services and recognize that cost, less estimated forfeitures, over the period that such services are performed. The Company adopted SFAS 123R on January 1, 2006 using the modified prospective transition method.

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Prior to adopting SFAS 123R, the Company accounted for stock-based compensation under SFAS 123, whereby the Company s policy was to recognize actual forfeitures of restricted stock only when they occurred rather than estimate them at the grant date and subsequently true-up estimated forfeitures to actuals. SFAS 123R requires companies to include forfeitures as part of the grant date estimate of compensation cost. Under the modified prospective method of adopting SFAS 123R, compensation cost recognized for 2006 includes (a) compensation cost for all restricted stock awards granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value, less estimated forfeitures, and (b) compensation cost for all share-based payments granted and vested subsequent to January 1, 2006, based on the grant date fair value, less estimated forfeitures. A cumulative effect of change in accounting principle to recognize the impact of including forfeitures, as part of the grant date estimate of compensation cost for all restricted stock awards granted prior to January 1, 2006, resulted in an insignificant credit to income in 2006. In accordance with the modified prospective method, prior period results have not been restated.

For the year ended December 31, 2006, the Company recognized share-based compensation costs of $3.4 million in general and administrative expenses and $0.6 million in exploration expenses in the Company s consolidated statement of income. The Company did not capitalize any share-based compensation costs for the year ended December 31, 2006.

The adoption of SFAS 123R had a minimal impact on the Company s income before income taxes and net income, and had no effect on basic or diluted earnings per share in 2006, as presented in the Company s consolidated statements of income.

Under the provisions of SFAS 123R, the recognition of deferred compensation at the date restricted stock is granted is no longer required. Therefore, in the first quarter of 2006, the amount that had been previously recorded as Deferred compensation in the Company s consolidated balance sheets was reversed in its entirety to additional paid-in capital. In addition, the adoption of SFAS 123R required that the Company classify certain tax benefits obtained upon restricted stock vesting, which result from tax deductions in excess of compensation cost recognized for book purposes, as financing cash flows rather than operating cash flows. The Company recognized $0.3 million in income tax benefits relating to share-based compensation for the year ended December 31, 2006.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). The adoption of SAB 108 did not have a material impact on the Company s consolidated financial position or results of operations. SAB 108 provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 is effective for fiscal years ending on or after November 15, 2006 and provides for a one-time transitional cumulative effect adjustment to beginning retained earnings as of January 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108.

New Accounting Pronouncements In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an interpretation of Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (FIN 48). The Company is currently evaluating the effect that the adoption of FIN 48 will have on its consolidated financial statements and has not yet determined whether or not the adoption will have a material impact on its consolidated financial position or results of operations. The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a

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measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006.

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* (SFAS 157). The adoption of SFAS 157 is not expected to have a material impact on the Company s consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop the measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years.

2. ACQUISITIONS AND DIVESTITURES

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 this transaction, the operator will pay 100% of Whiting s drilling and completion costs for the first three wells in the project.

Michigan Properties. On August 15, 2006, Whiting acquired 65 producing properties, a gathering line, gas processing plant and 30,437 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. The Company operates 85% of the acquired properties.

Oil Pipeline and Gathering System. On June 1, 2006, Whiting acquired the Postle field oil gathering system and oil transportation line extending 13 miles from the eastern side of the Postle field to a connection point with an interstate oil pipeline in Hooker, Oklahoma. Whiting purchased the oil gathering system and pipeline for $5.3 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 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 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.

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2005 Acquisitions

North Ward Estes and Ancillary Properties On October 4, 2005, the Company acquired the operated interest in the North Ward Estes field in Ward and Winkler counties, Texas, and certain smaller fields located in the Permian Basin. The purchase price was $459.2 million, consisting of $442.0 million in cash and 441,500 shares of the Company s common stock, for estimated proved reserves of 82.1 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of $5.58 per BOE of estimated proved reserves. Proved developed reserve quantities represented 36% of the total proved reserves acquired. The average daily production from the properties was 4.6 MBOE/d as of the acquisition effective date. The Company funded the cash portion of the purchase price with the net proceeds from the Company s public offering of common stock and private placement of 7% Senior Subordinated Notes due 2014.

Postle Field On August 4, 2005, the Company acquired the operated interest in producing oil and gas fields located in the Oklahoma Panhandle. The purchase price was $343.0 million for estimated proved reserves of 40.3 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of $8.52 per BOE of estimated proved reserves. Proved developed reserve quantities represented 57% of the total proved reserves acquired. The average daily production from the properties was 4.2 MBOE/d as of the acquisition effective date. The Company funded the acquisition through borrowings under Whiting Oil and Gas credit agreement.

Limited Partnership Interests On June 23, 2005, the Company acquired all of the limited partnership interests in three institutional partnerships managed by its wholly-owned subsidiary, Whiting Programs, Inc. The partnership properties are located in Louisiana, Texas, Arkansas, Oklahoma and Wyoming. The purchase price was $30.5 million for estimated proved reserves of 2.9 MMBOE as of the acquisition effective date of January 1, 2005, resulting in a cost of $10.52 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 0.7 MBOE/d as of the acquisition effective date. The Company funded the acquisition with cash on hand.

Green River Basin On March 31, 2005, the Company acquired operated interests in five producing natural gas fields in the Green River Basin of Wyoming. The purchase price was $65.0 million for estimated proved reserves of 8.4 MMBOE as of the acquisition effective date of March 1, 2005, resulting in a cost of $7.74 per BOE of estimated proved reserves. Proved developed reserve quantities represented 68% of the total proved reserves acquired. The average daily production from the properties was 1.1 MBOE/d as of the acquisition effective date. The Company funded the acquisition through borrowings under Whiting Oil and Gas credit agreement and with cash on hand.

As these acquisitions were recorded using the purchase method of accounting, the results of operations from the acquisitions are included with the Company s results from the respective acquisition dates noted above. The table below summarizes the allocation of the purchase price for each 2005 purchase transaction based on the acquisition date fair values of the assets acquired and the liabilities assumed (in thousands).

	Postle Field	N. Ward Estes and Ancillary	All Other Acquisitions
Purchase Price:			
Cash paid, net of cash acquired	$ 343,000	$ 442,000	$ 95,433
Common stock issued		17,175	
Total	$ 343,000	$ 459,175	$ 95,433
Allocation of Purchase Price:			
Working capital	$	$	$ 2,096
Oil and gas properties	343,513	463,340	95,832
Other long-term assets	243		
Other non-current liabilities	(756)	(4,165)	(2,495)
Total	$ 343,000	$ 459,175	$ 95,433

2004 Acquisitions

Permian Basin Properties On September 23, 2004, the Company acquired interests in seventeen fields in the Permian Basin of West Texas and Southeast New Mexico, including interests in key fields such as Parkway field in Eddy County, New Mexico; Would Have and Signal Peak fields in Howard County, Texas; Keystone field in Winkler County, Texas; and the DEB field in Gaines County, Texas. The purchase price was $345.0 million in cash and was funded through borrowings under the Company s bank credit agreement. Based on the purchase price and estimated proved reserves of 41.9 MMBOE on the effective date of the acquisition, the Company acquired these properties for $8.22 per BOE of proved reserves. Proved developed reserve quantities represented 59% of the total proved reserves acquired.

Equity Oil Company The Company acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, the Company issued 2.2 million shares of its common stock to Equity s shareholders and repaid all of Equity s outstanding debt of $29.0 million under its credit facility. Equity s operations are focused primarily in California, Colorado, North Dakota and Wyoming. Based on the purchase price of $72.6 million and estimated proved reserves of 14.6 MMBOE on the effective date of the acquisition, the Company acquired these properties for $4.98 per BOE of estimated proved reserves. Proved developed reserve quantities represented 79% of the total proved reserves acquired.

Other Cash Acquisitions of Properties

Colorado and Wyoming Properties On August 13, 2004, the Company acquired interests in four producing oil and natural gas fields in Colorado and Wyoming. The purchase price was $44.2 million in cash and was funded under the Company s bank credit agreement. Based on the purchase price of $44.2 million and estimated proved reserves of 6.6 MMBOE on the effective date of the acquisition, the Company acquired these properties for $6.66 per BOE of estimated proved reserves. Proved developed reserve quantities represented 82% of the total proved reserves acquired.

Louisiana and South Texas Properties On August 16, 2004, the Company acquired interests in five fields in Louisiana and South Texas. The purchase price was $19.3 million in cash and was funded under the Company s bank credit agreement. Based on the purchase price of $19.3 million and estimated proved reserves of 2.0 MMBOE on the effective date of the acquisition, the Company acquired these properties for $9.66 per BOE of estimated proved reserves. Proved developed reserve quantities represented 63% of the total proved reserves acquired.

Wyoming and Utah Properties On September 30, 2004, the Company acquired interests in three operated fields in Wyoming and Utah. The purchase price was $35.0 million in cash and was funded under the Company s bank credit agreement. Based on the purchase price of $35.0 million and estimated proved reserves of 5.1 MMBOE on the effective date of the acquisition, the Company acquired these properties for $6.84 per BOE of estimated proved reserves. Proved developed reserve quantities represented 92% of the total proved reserves acquired.

Mississippi Properties On November 3, 2004, the Company acquired an interest in the Lake Como field in Mississippi. The purchase price was $12.0 million in cash and was funded under the Company s bank credit agreement. Based on the purchase price of $12.0 million and estimated proved reserves of 1.8 MMBOE on the effective date of the acquisition, the Company acquired these properties for $6.78 per BOE of estimated proved reserves. Proved developed reserve quantities represented 86% of the total proved reserves acquired.

Additional Permian Basin Interest On December 31, 2004, the Company acquired an additional working interest in the Would Have field in Texas. The purchase price was $7.0 million in cash and was funded under the Company s bank credit agreement. Based on the purchase price and estimated proved reserves of 0.7 MBOE on the effective date of the acquisition, the Company acquired these properties for $10.32 per BOE of estimated proved reserves. Proved developed reserve quantities represented 17% of the total proved reserves acquired.

As these acquisitions were recorded using the purchase method of accounting, the results of operations from the acquisitions are included with the Company s results from the respective acquisition dates noted above. The table below summarizes the allocation of the purchase price for each 2004 purchase transaction based on the acquisition date fair values of the assets acquired and the liabilities assumed (in thousands).

	Permian Basin	Equity Oil	Other Cash Acquisitions
Purchase Price:			
Cash paid, net of cash received	$ 345,000	$ 256	$ 117,500
Debt assumed		29,000	
Stock issued		43,298	
Total	$ 345,000	$ 72,554	$ 117,500
Allocation of Purchase Price:			
Working capital	$	$ 3,277	$
Oil and gas properties	345,000	83,205	117,500
Deferred income taxes		(11,075)	
Other non-current liabilities, net		(2,853)	
Total	$ 345,000	$ 72,554	$ 117,500

Each of the business combinations completed during the past three years consisted of oil and gas properties or companies with oil and gas interests. The consideration 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 purchase, with no consideration being allocated to goodwill.

<u>Acquisition Pro Forma</u>

Pro forma effects of 2006 acquisitions were insignificant to the Company s 2006 results of operations. The following table reflects the pro forma results of operations for the year ended

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December 31, 2005 as though the above 2005 acquisitions had occurred on January 1, 2005. The pro forma results of operations for the year ended December 31, 2004 reflects all of the above acquisitions as though they had occurred on January 1, 2004. The pro forma information includes numerous assumptions and is not necessarily indicative of future results of operations.

	Year Ended December 31,			
	2005		2004	
	As Reported	Pro Forma	As Reported	Pro Forma
	(In thousands, except per common share data)			
Revenues and other income	$540,448	$652,634	$282,140	$501,586
Net income	121,922	155,462	70,046	106,063
Net income per common share, basic	3.89	4.05	3.38	3.82
Net income per common share, diluted	3.88	4.04	3.38	3.81

3. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2006 and 2005 (in thousands):

	December 31,	
	2006	2005
Credit agreement	$ 380,000	$ 260,000
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $687 and $848, respectively	147,820	148,014
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $2,424 and $2,916, respectively	217,576	217,084
7% Senior Subordinated Notes due 2014	250,000	250,000
Total debt	$ 995,396	$ 875,098

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, 2006, had a borrowing base of $875.0 million. 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. As of December 31, 2006, the outstanding principal balance under the credit agreement was $380.0 million.

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 from time to 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 from time to time in an aggregate amount not to exceed $50.0 million. As of December 31, 2006, letters of credit totaling $0.3 million were outstanding under the credit agreement.

Interest accrues, at Whiting Oil and Gas option, at either (1) 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 (2) 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. Whiting Oil and Gas has consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. 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, 2006, the weighted average interest rate on the entire outstanding principal balance under the credit agreement was 6.5%.

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 and requires the Company to maintain a debt to EBITDAX (as defined in the credit agreement) ratio of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement) 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 the Company. 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, 2006. The credit agreement is secured by a first lien on all of Whiting Oil and Gas properties included in the borrowing base for the credit 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 included in the borrowing base for the credit agreement as security for its guarantee.

Senior Subordinated Notes In October 2005, the Company issued $250.0 million of 7% Senior Subordinated Notes due 2014 at par. The estimated fair value of the Notes was $248.4 million as of December 31, 2006.

In April 2005, the Company issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. The 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 the notes yielding an effective interest rate of 7.5%. The estimated fair value of the Notes was $219.7 million as of December 31, 2006.

In May 2004, the Company issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. The 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 the notes yielding an effective interest rate of 7.4%. The estimated fair value of the Notes was $149.8 million as of December 31, 2006.

The notes are unsecured obligations of the Company and are subordinated to all of the Company s senior debt, which currently consists of Whiting Oil and Gas Corporation s credit agreement. The indentures governing the notes contain various restrictive covenants that are substantially identical and may limit the Company s and its subsidiaries ability to, among other things, pay cash dividends, redeem or repurchase the Company s capital stock or the Company s subordinated debt, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or

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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. In addition, Whiting Oil and Gas Corporation s credit agreement restricts the ability of the Company s subsidiaries to make certain payments, including principal on the notes, to the Company. The Company was in compliance with these covenants as of December 31, 2006. Three of the Company s wholly-owned operating subsidiaries, Whiting Oil and Gas, Whiting Programs, Inc. and Equity Oil Company (the Guarantors), have fully, unconditionally, jointly and severally guaranteed the Company s obligations under the notes. The Company does not have any subsidiaries other than the Guarantors, minor or otherwise, within the meaning of Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission.

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, 2006 was 5.4%. For the years ended December 31, 2006, 2005 and 2004, Whiting recognized realized gains (losses) of $(0.05) million, $1.5 million and $0.6 million, respectively, on the interest rate swap. As of December 31, 2006, the Company has recorded a long-term liability of $1.5 million related to the interest rate swap, which has been designated as a fair value hedge, with an offsetting reduction in 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 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 portion at December 31, 2006 and 2005 is $0.6 million and $0.1 million, respectively, and is recorded in accrued liabilities. The following table provides a reconciliation of the Company s asset retirement obligations for the years ended December 31, 2006 and 2005 (in thousands):

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	Year Ended December 31, 2006	2005
Beginning asset retirement obligation	$ 32,246	$ 31,639
Revisions in estimated cash flows	3,719	(9,348)
Additional liability incurred	2,260	8,086
Accretion expense	2,288	2,364
Obligations on sold properties	(1,432)	
Liabilities settled	(1,547)	(495)
Ending asset retirement obligation	$ 37,534	$ 32,246

5. DERIVATIVE FINANCIAL INSTRUMENTS

Whiting enters into derivative contracts, primarily costless collars, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. 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. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. 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 does not enter into derivative instruments for speculative or trading purposes.

At December 31, 2006, accumulated other comprehensive loss consisted of $9.3 million ($5.9 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. At December 31, 2005, accumulated other comprehensive loss consisted of $56.4 million ($34.6 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. At December 31, 2004, accumulated other comprehensive income consisted of $1.7 million ($1.0 million after tax) of unrealized losses on the Company s open commodity hedge derivatives.

For the years ended December 31, 2006, 2005 and 2004, Whiting recognized realized losses of $7.5 million, $33.4 million and $4.9 million, respectively, on commodity derivative settlements. Based on December 31, 2006 pricing, the Company does not expect to incur any commodity derivative settlement gains or losses during the next 12 months. The Company has hedged 5.0 MMBbl of crude oil volumes and 4,800 Mcfe of natural gas volumes through 2007 and 1.3 MMBbl of oil and no gas through 2008.

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

6. STOCKHOLDERS EQUITY

Common Stock Offerings In October 2005, the Company completed a public offering of 6,612,500 shares of its common stock. The offering was priced at $43.60 per share to the public. The number of shares includes the sale of 862,500 shares pursuant to the exercise of the underwriters over-allotment option.

In November 2004, the Company completed a public offering of 8,625,000 shares of its common stock. The offering was priced at $29.02 per share to the public. The number of shares includes the sale of 1,125,000 shares pursuant to the exercise of the underwriters over-allotment option.

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 participating employee may be granted options for more than 300,000 shares of common stock, stock appreciation rights with respect to more than 300,000 shares of common stock or more than 150,000 shares of restricted stock during any calendar year. In periods prior to January 1, 2006, the Company had granted 197,573 shares of restricted stock under this plan, of which 16,989 shares were forfeited and 6,122 shares were cancelled when used for employee tax withholdings. All restricted stock awards granted to date vest ratably over three years.

The following table shows a summary of the Company s nonvested restricted stock as of December 31, 2004, 2005 and 2006 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, 2004		$
Granted	112,921	$ 21.77
Forfeited	(7,724)	$ 21.05
Restricted stock awards nonvested, December 31, 2004	105,197	$ 21.83
Granted	84,652	$ 40.26
Vested	(28,699)	$ 21.73
Forfeited	(15,387)	$ 23.19
Restricted stock awards nonvested, December 31, 2005	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

The grant date fair value of restricted stock is determined based on the closing bid price of the Company s common stock on the grant date. The Company uses historical data and projections to estimate expected employee behaviors related to restricted stock forfeitures. SFAS 123R requires that expected forfeitures be included as part of the grant date estimate of compensation cost. Prior to adopting SFAS 123R, the Company reduced share-based compensation expense for forfeitures only when they occurred.

As of December 31, 2006, there was $3.0 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 1.7 years.

Rights Agreement On February 23, 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 on 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 par value (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 $.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.

7. 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 2006, 2005 and 2004 amounted to $13.2 million, $10.2 million and $6.5 million, respectively, charged to general and administrative expense and $2.5 million, $1.9 million and $0.6 million, respectively, charged to exploration expense. Pursuant to the terms of the Plan, (1) employees who terminate their employment with the Company vest at a rate of 20% per year in future Plan year payments, which are attributable to their interests in the income allocated to the Plan for such year; (2) employees will become fully vested at age 65, regardless of when their interests would otherwise vest; and (3) any forfeitures would 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, 2006, the Company used five-year average historical NYMEX prices of $46.20 for crude oil and $5.98 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, 2006, 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 $82.1 million. This amount includes $9.6 million attributable to proved undeveloped oil and gas properties and $15.7 million relating to the short-term portion of the Production Participation Plan liability, which has been accrued as a current payable for 2006 plan-year payments owed to employees. 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.

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

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	Year Ended December 31, 2006	2005
Beginning Production Participation Plan liability	$ 19,287	$ 9,579
Change in liability for accretion, vesting and change in estimate	21,849	21,829
Reduction in liability for cash payments accrued and recognized as compensation expense	(15,693)	(12,121)
Ending Production Participation Plan liability	$ 25,443	$ 19,287

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 table below 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, 2006	2005	2004
General and administrative expense	$ 5,196	$ 8,186	$ 1,574
Exploration expense	960	1,522	137
Total	$ 6,156	$ 9,708	$ 1,711

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 2006, 2005 and 2004 were $2.1 million, $1.2 million and $0.7 million, respectively. Employer contributions vest ratably at 20% per year over a five year period.

8. INCOME TAXES

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

	Year Ended December 31, 2006	2005	2004
Current income tax expense:			
Federal	$ 11,576	$ 5,076	$ 2,805
State	770	3,438	1,077
Total current income tax expense	12,346	8,514	3,882
Deferred income tax expense	64,562	65,662	40,077
Total	$ 76,908	$ 74,176	$ 43,959

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):

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	Year Ended December 31,		
	2006	2005	2004
U.S. statutory income tax expense	$ 81,645	$ 68,634	$ 39,902
State income taxes, net of federal benefit	907	7,028	4,100
Tax credits	(4,206)	(929)	
Statutory depletion	(1,245)	(434)	(53)
Enacted changes in state tax laws	(1,295)		
Change in valuation allowance	1,163		
Other	(61)	(123)	10
Total	$ 76,908	$ 74,176	$ 43,959

The principal components of the Company s deferred income tax assets and liabilities at December 31, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31,	
	2006	2005
Deferred income tax assets:		
Production Participation Plan liability	$ 9,357	$ 7,445
Derivative instruments	3,433	21,766
Tax sharing liability	9,993	11,129
Asset retirement obligations	11,673	9,591
Restricted stock compensation	1,849	1,035
Enhanced oil recovery credit carryforwards	6,894	
Alternative minimum tax credit carryforwards	9,900	
Foreign tax credit carryforwards	1,560	
Total deferred income tax assets	54,659	50,966
Less valuation allowances	(1,163)	
Net deferred income tax assets	53,496	50,966
Deferred income tax liabilities:		
Oil and gas properties	215,488	127,337
Other	14	85
Total deferred income tax liabilities	215,502	127,422
Total net deferred income tax liabilities	$ 162,006	$ 76,456

In 2006, the Company generated foreign tax credit carryforwards of $1.6 million, which expire between 2024 and 2026. A valuation allowance of $1.2 million has been established for these foreign tax credit carryforwards in order to reduce deferred tax assets to an amount that will, more likely than not be realized.

The Company is subject to the alternative minimum tax (AMT) principally due to accelerated tax depreciation, and for 2005 and 2004, the Company paid AMT of $2.5 million and $1.5 million, respectively. During 2006, the Company recognized AMT credits of $9.9 million for years 2004 to 2006, that are available to offset future regular federal income taxes. These credits do not expire and can be carried forward indefinitely.

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. At December 31, 2006, the

Company has recognized $6.9 million of enhanced oil recovery credits that are available to offset regular federal income taxes in the future. These credits can be carried forward and will expire in 2025. Federal EOR credits are subject to phase-out according to the level of average domestic crude prices. Due to recent high oil prices, the EOR credit was phased-out for 2006.

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

	Year Ended December 31,	
	2006	2005
Assets:		
Current deferred income taxes	$ 3,025	$ 15,121
Liabilities:		
Non-current deferred income taxes	165,031	91,577
Net deferred income tax liabilities	$ 162,006	$ 76,456

9. RELATED PARTY TRANSACTIONS

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, however, Alliant Energy was no longer a related party.

Tax Sharing Liability 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 the assets of Whiting and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. Whiting has adjusted deferred taxes on its balance sheet to reflect the new tax bases of the Company s 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 $38.6 million on an undiscounted basis, with a present value of $25.7 million.

During 2006 and 2005, the Company made payments $3.7 million and of $5.1 million, respectively, under this agreement and recognized accretion expense of $2.0 million and $2.7 million, respectively. The Company s estimate of payments to be made in 2007 under this agreement of $3.6 million is reflected as a current liability at December 31, 2006.

The Tax Separation and Indemnification Agreement provides that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in 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.

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 statement 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 and calculated its income tax expense on a separate return basis at Alliant Energy s effective tax rate less any research or Section 29 tax credits generated by the Company. Current tax due under this calculation was paid to Alliant Energy, and current refunds were received from Alliant Energy. Section 29 tax credits were generated in 2002 and are expected to be utilized by Alliant Energy in 2007. However, on a stand-alone basis Whiting would have been unable to use the credits in its 2002 tax return. The Company will be paid during 2007 for the Section 29 credits, which is when Alliant Energy will receive the benefit for them. The Company has a current receivable in the amount of $4.1 million as of December 31, 2006 for these credits.

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

10. COMMITMENTS AND CONTINGENCIES

Non-cancellable Leases The Company leases 87,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2010 and an additional 26,500 square feet of office space in Midland, Texas through February 15, 2012. Rental expense for 2006, 2005 and 2004 amounted to $1.9 million, $1.5 million and $0.9 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2006 are as follows (in thousands):

2007	$ 1,742
2008	1,759
2009	1,772
2010	1,540
2011	330
Thereafter	41
Total	$ 7,184

Purchase Contracts The Company has entered into two take-or-pay purchase agreements, one agreement in July 2005 for 9.5 years and one agreement in March 2006 for 8 years, whereby the Company has committed to buy certain volumes of CO_2 for a fixed fee subject to annual escalation. The purchase agreements are with different suppliers, and the CO_2 is for use in enhanced recovery projects in the Postle field in Texas County, Oklahoma and the North Ward Estes field in Ward County, Texas. Under the terms of the agreements, the Company is 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 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, the Company expects to avoid any payments for deficiencies. As of December 31, 2006, future commitments under the purchase agreements amounted to $308.9 million through 2014.

Drilling Contracts The Company entered into three separate three-year agreements in 2005 for drilling rigs, a two-year agreement in February 2006 for a workover rig, and a three-year agreement in September 2006 for an additional drilling rig, all operating in the Rocky Mountains region. As of December 31, 2006, these agreements had total commitments of $47.5 million and early termination would require maximum penalties of $32.7 million. No other drilling rigs working for the Company are currently under long-term contracts or contracts which cannot be terminated at the end of the well that is currently being drilled.

Price-Sharing Agreement The Company, as part of a 2002 purchase transaction, agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2007 increased to 50% of the actual price received in excess of $20.97 per barrel. As of December 31, 2006, approximately 40,300 net barrels of crude oil per month (5% of December 2006 net crude oil production) are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. During the years 2006, 2005 and 2004, the Company paid $9.4 million, $7.6 million and $4.8 million, respectively, under this agreement. As of December 31, 2006 and 2005, the Company had accrued an additional $0.6 million and $0.7 million, respectively, as currently payable.

Litigation The Company is subject to litigation claims and governmental and regulatory controls 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.

11. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Whiting Petroleum Corporation (the Company or Parent Issuer) is the issuer of 7.25% Senior Subordinated Notes due 2012, 7.25% Senior Subordinated Notes due 2013 and 7% Senior Subordinated Notes due 2014 (the Notes). The Notes are jointly and severally guaranteed on a full and unconditional basis by the Company s wholly-owned subsidiaries (Guarantor Subsidiaries). Presented on the following pages are the Company s condensed consolidating balance sheets, statements of income and statements of cash flows, as required by Rule 3-10 of Regulation S-X of the Securities Exchange Act of 1934, as amended.

The following condensed consolidating financial statements have been prepared from the Company s financial information on the same basis of accounting as the consolidated financial statements. Investments in our subsidiaries are accounted for under the equity method. Accordingly, the entries necessary to consolidate the Parent Issuer and Guarantor Subsidiaries are reflected in the Intercompany Eliminations column.

Condensed Consolidating Balance Sheets

December 31, 2006
(In thousands)

	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets	$ 7,263	$ 114,449	$	$ 121,712
Property and equipment, net		2,432,661		2,432,661
Intercompany receivable	1,066,633	(1,066,633)		
Investment in subsidiaries	750,546		(750,546)	
Non-current assets	21,103	20,457	(10,530)	31,030
Total assets	$ 1,845,545	$ 1,500,934	$ (761,076)	$ 2,585,403
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities	$ 12,477	$ 130,565	$	$ 143,042
Long-term debt	616,889	378,507		995,396
Deferred income taxes		175,561	(10,530)	165,031
Other long-term liabilities	23,607	71,657		95,264
Stockholders equity	1,192,572	744,644	(750,546)	1,186,670
Total liabilities and stockholders equity	$ 1,845,545	$ 1,500,934	$ (761,076)	$ 2,585,403

December 31, 2005
(In thousands)

	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets	$ 4,355	$ 127,809	$	$ 132,164
Property and equipment, net		2,062,858		2,062,858
Intercompany receivable	1,100,330	(1,100,330)		
Investment in subsidiaries	558,309		(558,309)	
Non-current assets	23,164	27,532	(10,522)	40,174
Total assets	$ 1,686,158	$ 1,117,869	$ (568,831)	$ 2,235,196
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities	$ 12,864	$ 155,703	$	$ 168,567
Long-term debt	616,236	258,862		875,098
Deferred income taxes		102,099	(10,522)	91,577
Other long-term liabilities	24,576	77,516		102,092
Stockholders equity	1,032,482	523,689	(558,309)	997,862

Total liabilities and stockholders equity	$ 1,686,158	$ 1,117,869	$ (568,831)	$ 2,235,196

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Condensed Consolidating Statements of Income

Year Ended December 31, 2006
(In thousands)

	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues and other income	$	$ 778,827	$	$ 778,827
Operating costs and expenses		393,568		393,568
General and administrative	3,367	34,441		37,808
Interest expense	50,151	23,338		73,489
Other operating expenses		40,690		40,690
Equity in earnings of subsidiaries	(192,237)		192,237	
Income (loss) before income taxes	138,719	286,790	(192,237)	233,272
Income tax (benefit) expense	(17,645)	94,553		76,908
Net income (loss)	$ 156,364	$ 192,237	$ (192,237)	$ 156,364

Year Ended December 31, 2005
(In thousands)

	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues and other income	$	$ 540,448	$	$ 540,448
Operating costs and expenses		245,291		245,291
General and administrative	2,861	27,746		30,607
Interest expense	29,927	12,118		42,045
Other operating expenses		26,407		26,407
Equity in earnings of subsidiaries	(142,308)		142,308	
Income (loss) before income taxes	109,520	228,886	(142,308)	196,098
Income tax (benefit) expense	(12,402)	86,578		74,176
Net income (loss)	$ 121,922	$ 142,308	$ (142,308)	$ 121,922

Year Ended December 31, 2004
(In thousands)

	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues and other income	$	$ 282,140	$	$ 282,140
Operating costs and expenses		125,015		125,015
General and administrative	580	18,644		19,224
Interest expense	6,608	9,248		15,856
Other operating expenses		8,040		8,040
Equity in earnings of subsidiaries	(74,462)		74,462	
Income (loss) before income taxes	67,274	121,193	(74,462)	114,005
Income tax (benefit) expense	(2,772)	46,731		43,959

Net income (loss)	$	70,046	$	74,462	$	(74,462)	$	70,046

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Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2006
(In thousands)

	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities	$ (29,802)	$ 441,011	$	$ 411,209
Cash flows from investing activities:				
Cash acquisition capital expenditures		(87,562)		(87,562)
Drilling and development capital expenditures		(464,407)		(464,407)
Other investing activities		24,390		24,390
Net cash used in investing activities		(527,579)		(527,579)
Cash flows from financing activities:				
Issuance of long-term debt under credit agreement		325,000		325,000
Payments on long-term debt under credit agreement		(205,000)		(205,000)
Intercompany receivable	33,257	(33,257)		
Other financing activities	(3,455)	(185)		(3,640)
Net cash provided by financing activities	29,802	86,558		116,360
Net change in cash and cash equivalents		(10)		(10)
Cash and cash equivalents:				
Beginning of period		10,382		10,382
End of period	$	$ 10,372	$	$ 10,372

Year Ended December 31, 2005
(In thousands)

	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities	$ (8,475)	$ 338,668	$	$ 330,193
Cash flows from investing activities:				
Cash acquisition capital expenditures		(900,332)		(900,332)
Drilling and development capital expenditures		(196,163)		(196,163)
Other investing activities		(30,433)		(30,433)
Net cash used in investing activities		(1,126,928)		(1,126,928)
Cash flows from financing activities:				
Issuance of common stock	277,117			277,117
Issuance of Senior Subordinated Notes	466,715			466,715
		395,000		395,000

Issuance of long-term debt under credit agreement				
Payments on long-term debt under credit agreement		(310,000)		(310,000)
Intercompany receivable	(718,070)	718,070		
Other financing activities	(17,287)	(6,088)		(23,375)
Net cash provided by financing activities	8,475	796,982		805,457
Net change in cash and cash equivalents		8,722		8,722
Cash and cash equivalents:				
Beginning of period		1,660		1,660
End of period	$	$ 10,382	$	$ 10,382

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Condensed Consolidating Statements of Cash Flows (continued)
Year Ended December 31, 2004
(In thousands)

	Parent Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities	$ 6,974	$ 127,142	$	$ 134,116
Cash flows from investing activities:				
Cash acquisition capital expenditures		(451,231)		(451,231)
Drilling and development capital expenditures		(79,376)		(79,376)
Other investing activities		6,164		6,164
Net cash used in investing activities		(524,443)		(524,443)
Cash flows from financing activities:				
Issuance of common stock	239,686			239,686
Issuance of Senior Subordinated Notes	148,890			148,890
Issuance of long-term debt under credit agreement		445,800		445,800
Payments on long-term debt under credit agreement		(484,800)		(484,800)
Intercompany receivable	(390,919)	390,919		
Other financing activities	(4,631)	(6,543)		(11,174)
Net cash provided by financing activities	(6,974)	345,376		338,402
Net change in cash and cash equivalents		(51,925)		(51,925)
Cash and cash equivalents				
Beginning of period		53,585		53,585
End of period	$	$ 1,660	$	$ 1,660

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12. OIL AND GAS ACTIVITIES

The Company s oil and gas activities were entirely within the United States. Costs incurred in oil and gas producing activities were as follows (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Unproved property acquisition	$ 38,628	$ 16,124	$ 4,401
Proved property acquisition	29,778	906,208	525,563
Development	408,828	215,162	74,476
Exploration	81,877	22,532	9,739
Total	$ 559,111	$ 1,160,026	$ 614,179

During 2006, 2005 and 2004, additions to oil and gas properties of $2.3 million, $8.1 million and $7.3 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,	
	2006	2005
Proven oil and gas properties	$ 2,828,282	$ 2,353,372
Unproven oil and gas properties	55,297	21,671
Accumulated depreciation, depletion and amortization	(489,550)	(334,825)
Oil and gas properties, net	$ 2,394,029	$ 2,040,218

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,		
	2006	2005	2004
Beginning balance at January 1	$ 4,193	$ 2,937	$
Additions to capitalized exploratory well costs pending the determination of proved reserves	51,798	6,500	5,562
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(43,276)	(5,244)	(2,625)
Capitalized exploratory well costs charged to expense	(2,521)		
Ending balance at December 31	$ 10,194	$ 4,193	$ 2,937

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