WHITING PETROLEUM CORPORATION
2004 ANNUAL REPORT

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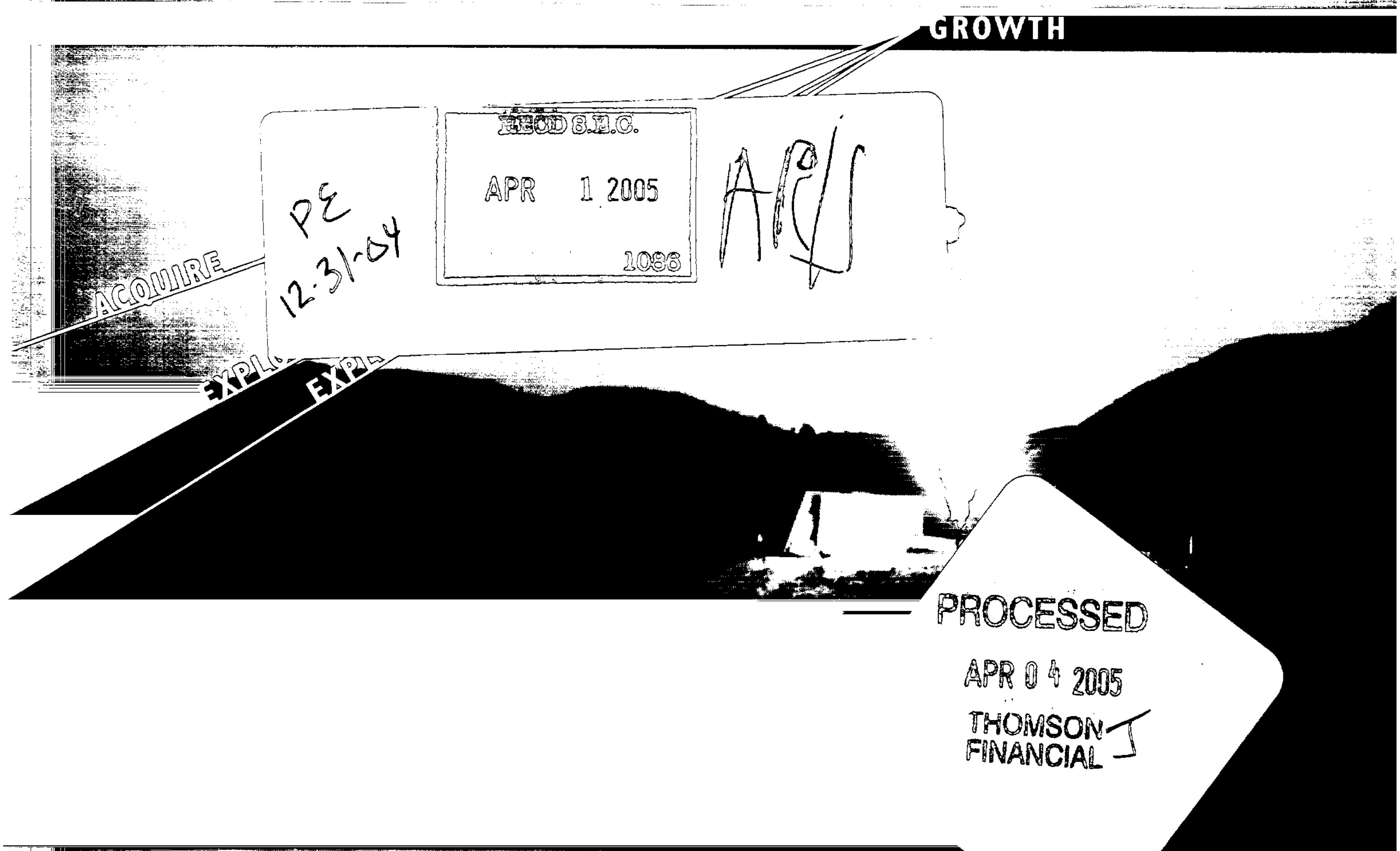

CORPORATE PROFILE

Whiting Petroleum Corporation is a growing energy company based in Denver, Colorado. The Company owns and operates oil and gas properties primarily in the Rocky Mountain, Permian Basin, Gulf Coast, Michigan and Mid-Continent regions of the United States. The Company trades publicly under the symbol WLL on the New York Stock Exchange.

Whiting's growth strategy is focused on increasing reserves and production per share through producing property acquisitions, exploitation and exploration. Whiting strives to increase reserves and daily production through complementary acquisitions, efficiently exploiting our undeveloped oil and natural gas reserves, and drilling a number of exploratory wells in our core regions.

Whiting's acquire, exploit and explore strategy resulted in year-end 2004 total proved reserves of 865.4 billion cubic feet of natural gas equivalents (Bcfe), a 97% increase over 2003. Proved reserves per share climbed to 29.1 thousand cubic feet of natural gas equivalents (Mcfe). Our 2004 all-in finding and development cost of $1.28 per Mcfe, low by industry standards, is a mark of a disciplined acquisition and development strategy.

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COVER PHOTO

Whiting's M.O.I. 14-33H horizontal Nisku A discovery well in the Williston Basin, Billings County, ND

This annual report contains forward-looking statments. These statements should be considered in light of the disclaimer set forth on page 41 of the enclosed Annual Report on Form 10-K.

TWO DECADES OF STRONG PERFORMANCE

1980

- Whiting organized

1983

- Whiting merged with Hingeline-Overthrust and Keba Oil & Gas to become a public company

1985 – 1991

- Whiting invested $134 million in seven partnerships for seven life insurance companies, receiving 13%-17% interests in partnerships

1992

- Acquired by Alliant Energy for $27.5 million

1999

- Proved reserves totaled 194 Bcfe at year-end

2000

- Initiated plan to grow Whiting, invested $139 million

2001

- Invested $100 million – Purchased operating interest in five Edwards Lime Fields

2002

- Invested $165 million
- Purchased operating interest in North Dakota Big Stick and North Elkhorn Ranch Fields
- Purchased operating interest in South Texas Agua Dulce Field

2003

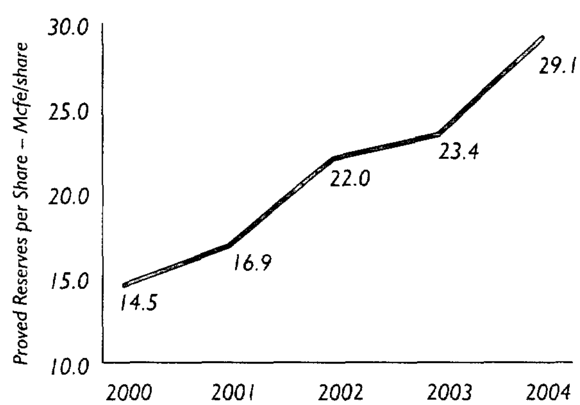
- Completed IPO in November 2003 at $15.50 per share
- Oil and gas revenue reached $175.7 million
- Annual production of 37.2 Bcfe
- Reserves increased to 438.8 Bcfe
- Replaced 170% of 2003 production

2004

- Issued $150 million of 8-year Senior Sub Notes at 7.25% rated B2/B-
- 7/20 – Closed $72.6 million merger of Equity Oil Co.
- 8/13 – Closed $44.2 million cash acquisition of Colorado/Wyoming properties.
- 8/16 – Closed $19.3 million cash acquisition of Louisiana/Texas properties.
- 9/23 – Closed $345.0 million cash acquisition of Permian Basin properties.
- 9/30 – Closed $35.0 million cash acquisition of Wyoming/Utah properties
- 11/22 – Issued 8.625 million common shares, receiving net proceeds of $239.7 million
- 11/04-12/04 – Closed $19 million cash acquisitions of Mississippi field and additional interest in West Texas/Permian Would Have Field
- Achieved record annual production of 47.0 Bcfe
- Proved reserves hit record high of 865.4 Bcfe
- Replaced 1007% of 2004 production

WHITING'S GROWTH STRATEGY IS FOCUSED ON INCREASING RESERVES AND PRODUCTION PER SHARE THROUGH PRODUCING PROPERTY ACQUISITIONS, EXPLOITATION AND EXPLORATION.

GROWING PROVED RESERVES PER SHARE

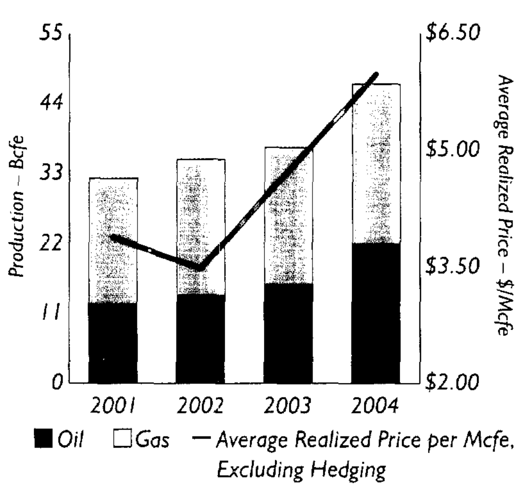


FINANCIAL AND OPERATIONS SUMMARY

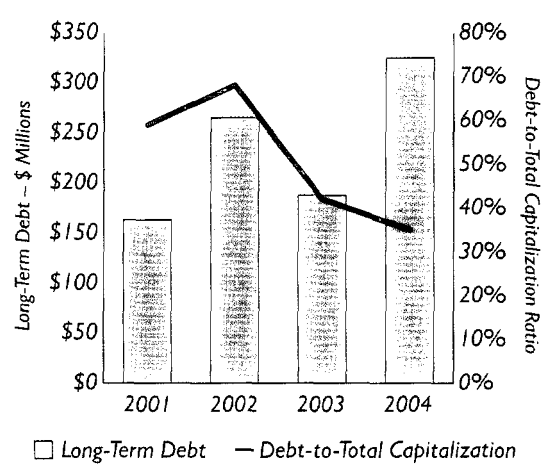
(Dollars in Thousands, Except per Share or Ratio Amounts)	2004	2003	2002	2001
Income Statement and Cash Flow				
Oil and Gas Sales	$ 281,057	$ 175,731	$ 122,709	$ 125,286
Net Income	$ 70,046	$ 18,285	$ 7,729	$ 41,243
Net Income per Share	$ 3.38	$ 0.98	$ 0.41	$ 2.20
Weighted Average Shares Outstanding (Diluted)	20,768	18,750	18,750	18,750
Net Cash Provided by Operating Activities	$ 135,547	$ 96,362	$ 62,581	$ 62,347
Net Cash Used in Investing Activities	$ (525,874)	$ (52,008)	$ (157,475)	$ (86,485)
Net Cash Provided by Financing Activities	$ 338,402	$ 4,398	$ 98,710	$ 23,869
Balance Sheet				
Total Assets	$ 1,092,206	$ 536,285	$ 448,468	$ 319,836
Long-Term Debt	$ 325,261	$ 188,017	$ 265,472	$ 163,591
Stockholders' Equity	$ 612,386	$ 259,578	$ 122,818	$ 111,467
Debt-to-Capitalization Ratio	35%	42%	68%	59%
Production and Commodity Prices				
Oil Production, MBbl	3,662	2,594	2,319	2,088
Natural Gas Production, MMcf	25,071	21,596	21,366	19,751
Production, MMcfe	47,043	37,160	35,280	32,279
Oil Sales Price, per Bbl Average, Excluding Hedging	$ 38.72	$ 27.50	$ 23.35	$ 23.85
Natural Gas Sales Price, per Mcf Average, Excluding Hedging	$ 5.56	$ 4.78	$ 3.21	$ 3.82
Average Sales Price, per Mcfe, Excluding Hedging	$ 5.97	$ 4.73	$ 3.48	$ 3.88
Lease Operating Expense, per Mcfe	$ 1.15	$ 1.16	$ 0.93	$ 0.92
Production Tax Expense, per Mcfe	$ 0.36	$ 0.29	$ 0.21	$ 0.20

Year-End 2004 Well Count and Acreage Statistics	**Gross**	**Net**
Total Wells	6,970	2,021
Developed Acreage	752,000	300,400
Undeveloped Acreage	608,800	315,700

PRODUCTION



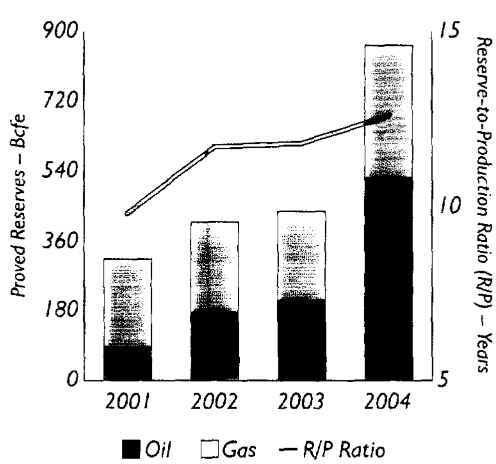
LONG-TERM DEBT



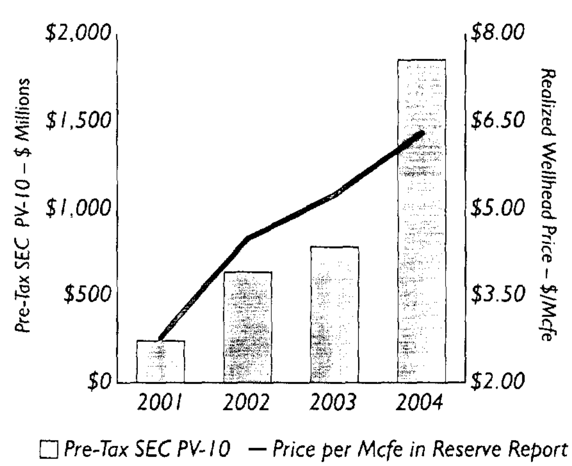
	2004	2003	2002	2001
Reserves				
Oil, MBbl	87,588	34,640	29,458	14,805
Natural Gas, MMcf	339,856	231,011	235,988	227,521
Reserves, MMcfe	865,378	438,851	412,736	316,351
Reserves-to-Production Ratio	12.6	11.8	11.7	9.8
Average Wellhead Oil Price per Bbl in Reserve Report	$ 40.58	$ 29.43	$ 28.21	$ 17.30
Average Wellhead Gas Price per Mcf in Reserve Report	$ 5.56	$ 5.52	$ 4.39	$ 2.72
Present Value at 10%, Before Income Taxes	$ 1,851,600	$ 784,600	$ 638,600	$ 244,600

	Year ended December 31,				Four-Year
	2004	2003	2002	2001	Total/Avg.
Calculation of Finding, Development and Acquisition (FD&A) Cost					
Acquisition and Development Costs Incurred	$ 606,899	$ 54,678	$ 166,506	$ 98,995	$ 927,078
Reserve Additions, Including Revisions, MMcfe	473,640	63,275	132,618	86,490	756,023
All-Sources FD&A Cost Per Mcfe	$ 1.28	$ 0.86	$ 1.26	$ 1.14	$ 1.23
Calculation of Reserve Replacement Percentage					
Reserve Additions, Including Revisions, MMcfe	473,640	63,275	132,618	86,490	756,023
Production of Oil and Natural Gas, MMcfe	47,038	37,160	35,280	32,279	151,757
Reserve Replacement Percentage	1007%	170%	376%	268%	498%
Reconciliation to Capital Expenditures per Consolidated Statement of Cash Flows					
Acquisition and Development Costs Incurred	$ 606,899	$ 54,678	$ 166,506	$ 98,995	$ 927,078
Equity Oil Merger Allocated Property Cost	(72,554)	-	-	-	(72,554)
Furniture and Fixtures	1,870	516	748	1,419	4,553
Exploration Cost	(4,177)	(3,186)	(1,811)	(793)	(9,967)
Capital Expenditures, per Consolidated Statement of Cash Flows	$ 532,038	$ 52,008	$ 165,443	$ 99,621	$ 849,110

RESERVES



PROVED RESERVES PRE-TAX SEC PV-10



LETTER TO THE SHAREHOLDERS

Whiting realized record-breaking performance in 2004 by delivering outstanding results from all aspects of our acquire, exploit and explore strategy. Specifically, we achieved the following Company records:

- Year end 2004 reserves hit a record high of 865.4 Bcfe, 97% greater than the 438.8 Bcfe at December 31, 2003
- Although all acquisitions were closed in the second half of the year, average daily 2004 production hit a record high of 128.5 million cubic feet of natural gas equivalents (MMcfe) per day, 26% greater than 2003 volumes of 101.8 MMcfe per day
- Acquired a record volume of proved reserves, 436.1 Bcfe at a cost of $1.23 per Mcfe
- Replaced 1007% of our 2004 production at an attractive all-in finding and development cost of $1.28 per Mcfe
- Oil and gas revenue rose more than 60% to $281.1 million in 2004 from $175.7 million in 2003
- Record net income of $70.0 million in 2004, 283% higher than 2003
- Net cash provided by operating activities increased 41% from $96.4 million in 2003 to $135.5 million in 2004

Our continued focus is to increase long-term shareholder value by investing in long-lived oil and gas projects with attractive rates of return on capital employed. Our strategy of acquire, exploit and explore has been effective as demonstrated by our results. Since our November 2003 initial public offering at a price of $15.50 per share our stock price has increased by 169% to $41.70 per share as of February 25, 2005.

Enhancing Shareholder Value during ALL CYCLES

Whiting's management team has many years of industry experience. Over the course of the Company's history, we have learned to execute our strategy and build our assets through periods of extreme oil and natural gas price volatility.

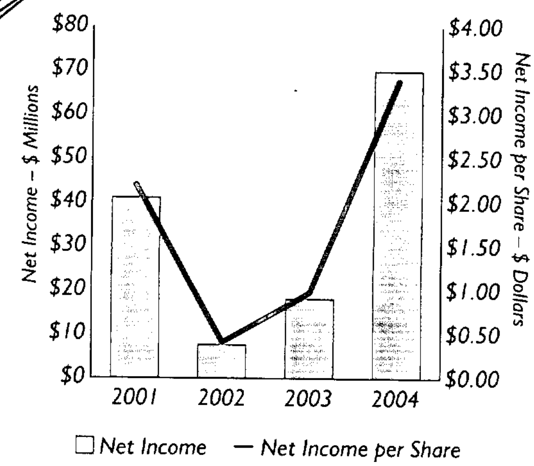
As crude oil and natural gas prices continue to fluctuate, Whiting sees more, not fewer, opportunities for growth. Our confidence in the future is grounded in our acquire, exploit and explore strategy, and the results it has achieved over the last 24 years. Each price environment whether high or low relative to historical standards brings with it a unique set of opportunities. Whiting's dedicated, experienced employees work each day to uncover value in the fields we own as well as fields we are evaluating to acquire. Our people and their knowledge and dedication is our strength.

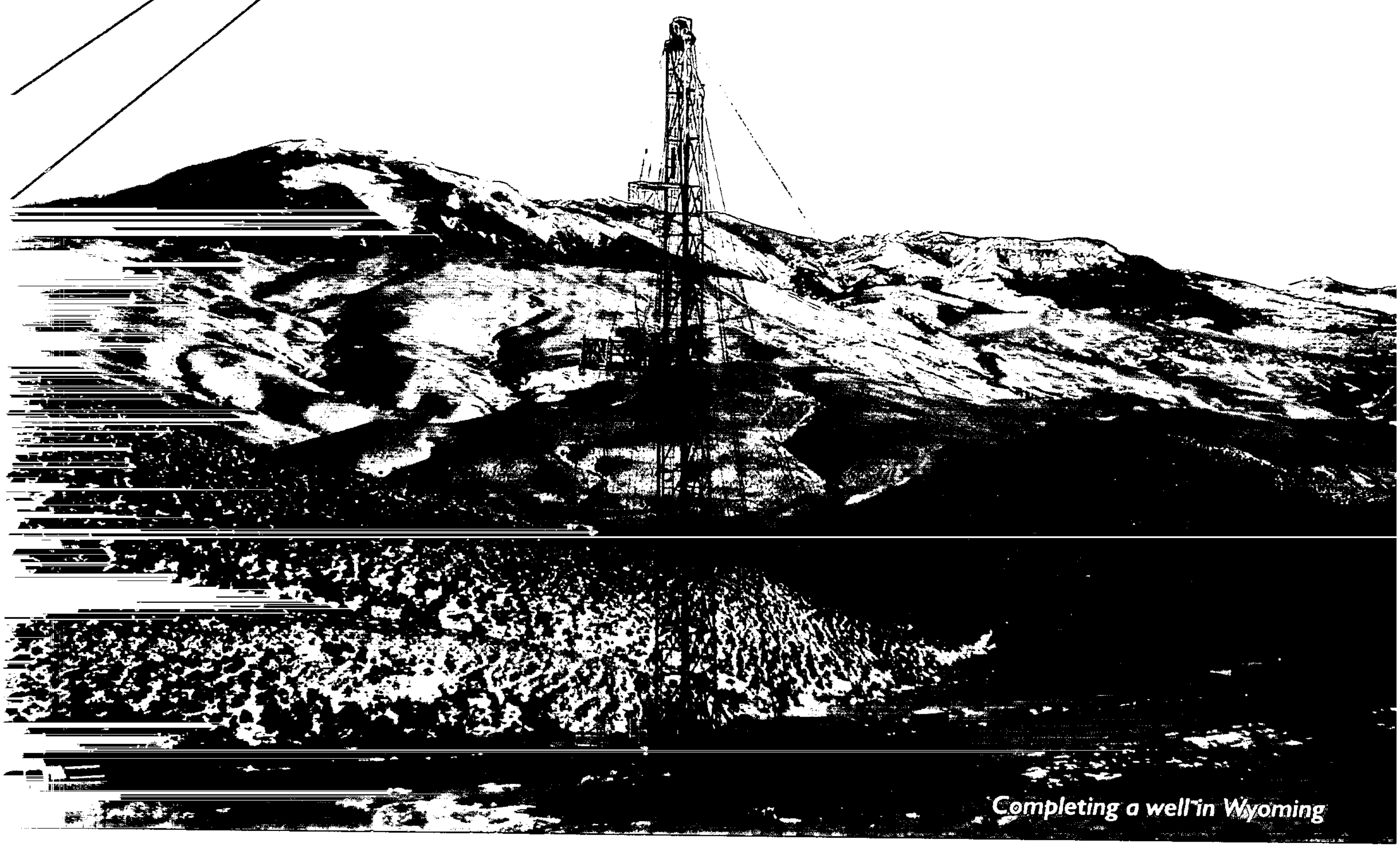
Over the last four years, we have purchased and developed approximately 756 Bcfe of reserves at an all-in finding and development cost of $1.23 per Mcfe. During the same four-year period, Whiting's average realized product sales price was $4.64 per Mcfe. In 2004, we realized cash margins of about 60% of our $5.97 average realized sale price per Mcfe.

Commodity Prices

The historic volatility in oil and natural gas prices is a reflection of imbalances of supply and demand in the market. Recently, the convergence of world energy consumption and world supply has caused oil and natural gas prices to rise. World oil and natural gas demand is growing, heavily influenced by industrial output and economic activity in China, India and Southeast Asia. The International Energy Agency (IEA)

NET INCOME





Completing a well in Wyoming

WE HAVE A DISCIPLINED APPROACH TO EVALUATING ACQUISITIONS IN OUR CORE AREAS. OUR ACQUISITION APPROACH IS COUPLED WITH A STUDIED AND INFORMED PROGRAM OF EXPLOITATION DRILLING AND IMPROVED RECOVERY PROJECTS.

is currently predicting 2005 oil demand will reach 83.7 million barrels of oil per day. This represents an increase of 1.3 million barrels a day over 2004. Some analysts predict an even larger increase in demand. Continued growth in oil demand, the apparently maturing worldwide supply base and the desire of foreign oil producers to realize increased revenue by controlling the level of their oil production has been reflected in a rising oil price. Whiting recognizes the volatility of oil and natural gas prices and attempts to mitigate the risk of falling prices and its effect on our Company by using costless collar commodity hedges, constantly working to reduce our cost structure and, over time, maintaining a prudent capital structure. We take these actions because based on December 2004 production rates, our annual net cash flow from operations moves approximately $4.2 million for every $0.15 change in realized natural gas prices and $5.6 million when realized oil prices move $1.00 per barrel.

Our 2004 Results

For the year ended December 31, 2004, oil and gas sales were $281.1 million compared to $175.7 million in 2003. Net cash provided by operating activities increased 41% to $135.5 million, and net income was $70.0 million or 283% higher than the $18.3 million of net income in 2003. In 2004, we received weighted average wellhead prices of $38.72 a barrel for our crude oil production and $5.56 per Mcf for our natural gas production.

Average daily equivalent production increased to 128.5 MMcfe in 2004 an increase of 26% over the 101.8 MMcfe per day in 2003. The December 2004 exit rate was 188 MMcfe per day. Total proved reserves rose to 865.4 Bcfe which is nearly double the year-end 2003 level of 438.8 Bcfe. The increase in reserves came through acquisitions, development, exploitation and exploration drilling.

Our Growth Philosophy

The execution of this growth strategy is how we differentiate ourselves. We have a disciplined approach to evaluating acquisitions within our areas of focus. We have a team of reservoir engineers dedicated to evaluating and understanding the value of broadly marketed acquisition targets as well as privately offered asset packages and corporate transactions. Our acquisition approach is coupled with a studied and informed program of exploitation drilling and improved recovery projects. This combination enhances Whiting's reserves, daily production, cash flow and return on capital employed. We have historically achieved significant growth,

Oil wells producing in Wyoming

strong returns and enhanced shareholder value through the execution of this strategy. Specifically, in 2004 we accomplished the following:

- Acquired 436.1 Bcfe of proved producing properties at an average cost of $1.23 per Mcfe. Our focus is to acquire properties in our core areas at an attractive rate of return on the existing proved developed producing reserves and further increase value through exploitation and exploration drilling and improved recovery projects.
- Drilled 169 wells investing $85.7 million of exploration and development capital. This investment added 60.2 Bcfe of proved reserves at a cost of $1.42 per Mcfe.
- Made exploratory discoveries in the Nisku A zone in the Williston Basin. A significant portion of our acreage in the horizontal Nisku play is a result of an acquisition we completed in 2002. This position was further enhanced with the merger with Equity Oil. Whiting holds a dominant position in this evolving play.

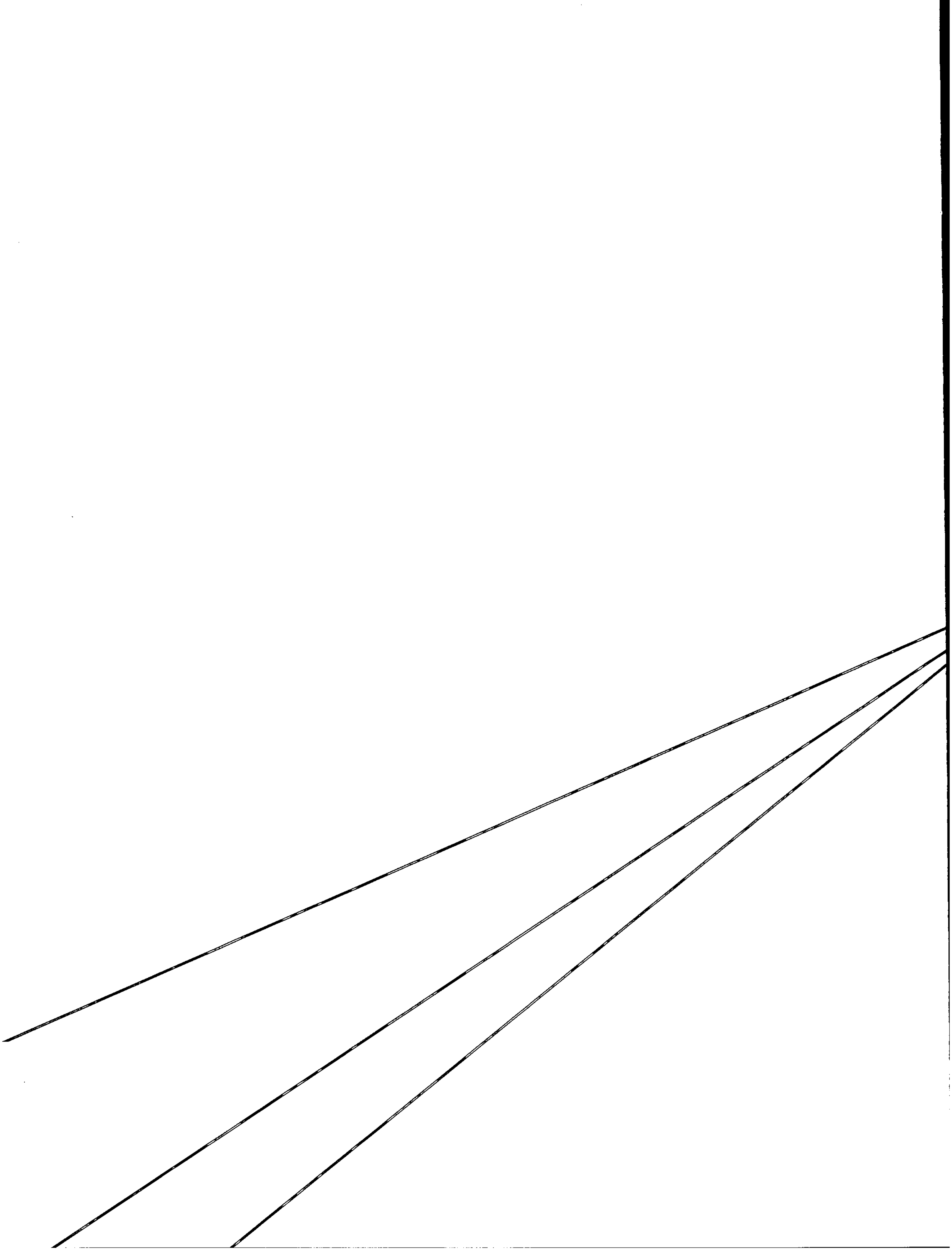
Committed to Shareholder Growth

Whiting posted outstanding results for 2004. Your support and Whiting's outstanding team of dedicated employees created these results. We look optimistically to the challenges and opportunities we will face in 2005. We will remain focused on our acquire, exploit, and explore strategy in order to accretively grow our reserves and production per share. We will continue to be disciplined and vigilant in evaluating acquisitions. Whiting's current inventory of development and exploitation opportunities is the strongest in our history. Whiting is well positioned for organic drill-bit production growth. As always we remain focused on creating long-term shareholder value. On behalf of our Board of Directors, officers and employees, thank you for your continued trust and support.

Sincerely,

James J. Volker

James J. Volker
Chairman of the Board, President and Chief Executive Officer
February 25, 2005



GROWTH

We will remain focused on our acquire, exploit, and explore strategy in order to accretively grow our reserves and production per share.

2004 MERGER AND ACQUISITION SUMMARY

	Purchase Price (In millions)	Proved Reserves (Bcfe)	Percent Natural Gas	Percent Developed	Average Daily Production (MMcfe/d)	R/P Ratio	Purchase Price Metrics[1] $/Proved Reserves ($/Mcfe)	$/Daily Production ($Mcfe/d)
Equity Oil Company	$ 72.6	87.7	32	79	18.2	13.2x	$ 0.83	$ 3,989
Colorado/ Wyoming	44.2	39.8	54	82	8.9	12.3	1.11	4,989
Louisiana/Texas	19.3	12.0	91	63	3.7	8.9	1.61	5,216
Permian Basin Properties	345.0	251.1	18	59	37.8	18.2	1.37	9,118
Wyoming/Utah	35.0	30.8	35	92	6.3	13.4	1.14	5,556
Misssissippi/Permian addl. Interest	19.0	14.7	13	62	2.5	16.1	1.29	7,580
Total	$ 535.1	436.1	27%	68%	77.4	15.4x	$ 1.23	$ 6,913

(1) Purchase price metrics based on proved reserves as of the effective date of the acquisition and production at announcement date.

In 2004 Whiting completed six property acquisitions and the merger with Equity Oil. The Company purchased $535.1 million of properties, adding 436.1 Bcfe of proved reserves from acquisitions at a cost of $1.23 per Mcfe.

1) Equity Oil Company

Whiting completed the merger of Equity Oil Company on July 20, 2004. Whiting issued 2.2 million new shares at an exchange ratio of 0.185 shares of Whiting stock for each share of Equity common stock and assumed $29 million of Equity's bank debt resulting in a total acquisition cost of $72.6 million. Immediately after closing, Whiting repaid all of Equity's debt. Many of Equity's properties were in the area of Whiting's operations and included assets located in the Williston, Big Horn, Green River and Piceance Basins. The Equity asset base coupled with Whiting's technical and financial strength position us for strong future growth from these assets specifically:

- Williston Basin – acreage adjacent to Whiting's operations increased the Company's position in the area of its new horizontal Nisku A exploration play.
- Green River Basin – the Company is pursuing development of proved undeveloped and other reserve categories through a multi-well development program in the Siberia Ridge Field in Sweetwater County, Wyoming. The primary target in the field is the Cretaceous-Almond formation at a depth of 10,500 feet.

2) Colorado / Wyoming

This acquisition of four producing oil and gas fields in Colorado and Wyoming from an undisclosed seller closed on August 13, 2004. One field of note is Hiawatha West Field which is located on the structural trend of the Cherokee Arch along the state line between Colorado and Wyoming. This field provides Whiting with multiple drilling opportunities targeting the middle Lewis and Lower Fort Union sandstones at depths of 4,200 to 4,500 feet. In 2005, Whiting plans to drill six wells in the Hiawatha Field.

3) Louisiana / Texas

On August 16, 2004, Whiting closed the purchase of several fields located in Vermilion and Claiborne Parishes, Louisiana and Aransas County, Texas. The Lisbon Field in Claiborne Parish, Louisiana has both down-spacing drilling and behind-pipe recompletion opportunities in the Cotton Valley formation.

4) Permian Basin Properties

Whiting closed this acquisition on September 23, 2004. The purchase included an interest in 17 fields in the Permian Basin of West Texas and Southeast New Mexico. Nearly three-quarters of these long-lived Permian Basin reserves acquired are concentrated in the following fields:

New Mexico:
- Parkway Field, Eddy County

Texas:
- Would Have Field, Howard County
- Signal Peak Field, Howard County
- Keystone Field, Winkler County
- DEB Field, Gaines County

These fields contain significant potential for development, exploitation, exploration and secondary recovery projects. Please refer to the Drilling and Operations Overview – Exploit and Explore section for further discussion.

5) Wyoming / Utah

Whiting closed this acquisition on September 30, 2004. The primary assets acquired were the Luckey Ditch and Whiskey Springs Units in Uinta County, Wyoming and the Bridger Lake Unit in Summit County, Utah. These fields have recompletion and down-spacing potential.

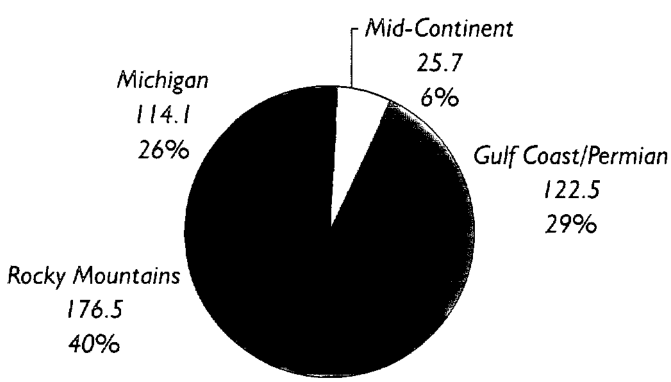
6) Mississippi and Additional Permian Interest

Whiting completed acquisitions on November 3, 2004 and December 31, 2004 with private sellers for properties located in Mississippi and Texas. The Mississippi purchase was for proved reserves in the Lake Como Field in Jasper County. In Texas, Whiting acquired an additional working interest in the Would Have Field in Howard County of the Permian Basin. This purchase increased Whiting's average working interest in the Would Have Field to approximately 86%. Would Have provides Whiting with several drilling opportunities for proved and non-proved reserves.

2003 YEAR END PROVED RESERVES BY AREA

439.8 BCFE

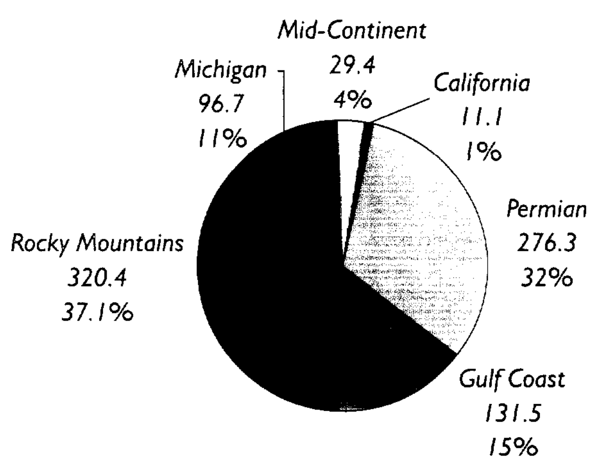
% OF TOTAL



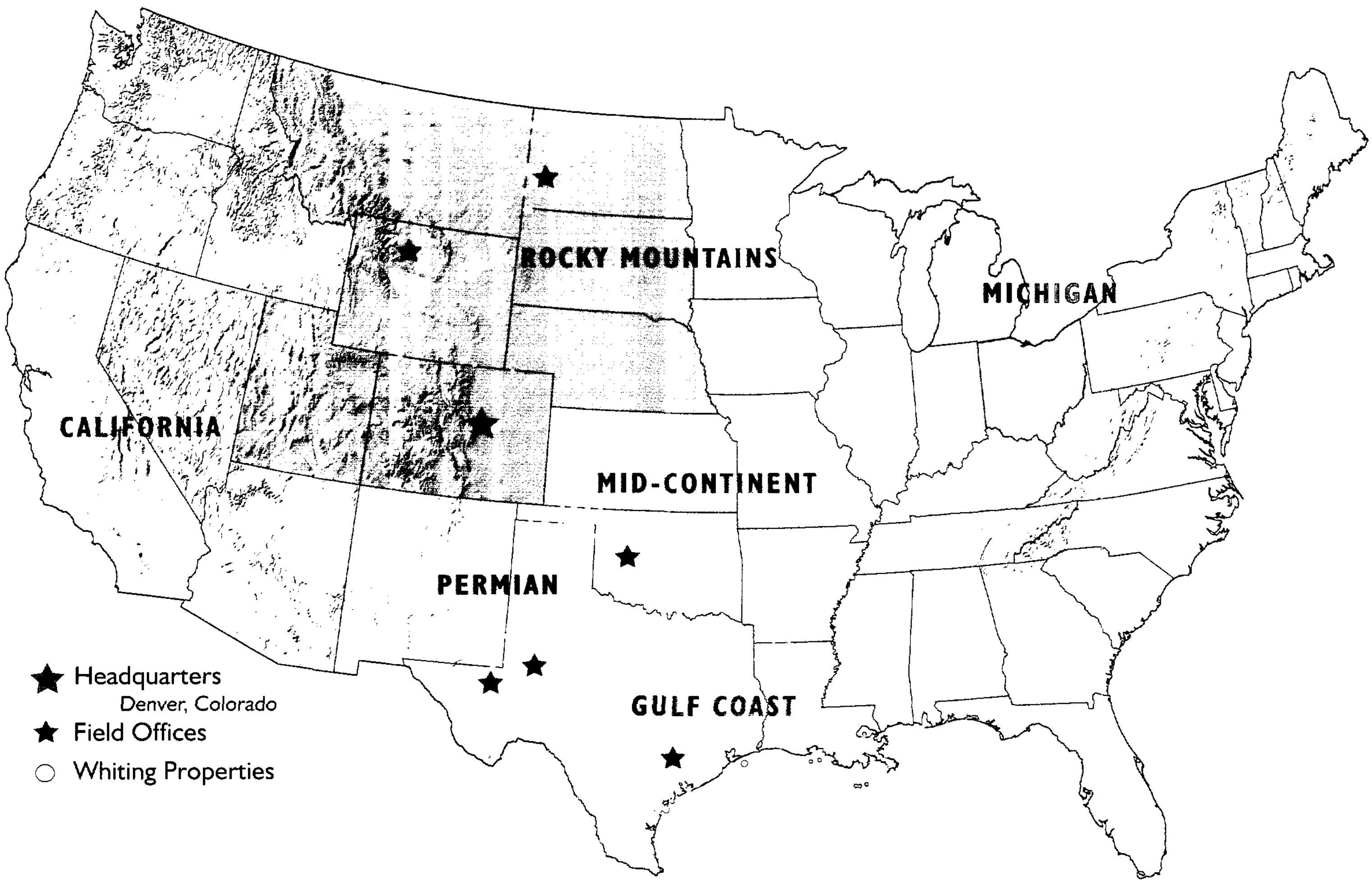
2004 YEAR END PROVED RESERVES BY AREA

865.4 BCFE

% OF TOTAL



DRILLING AND OPERATIONS OVERVIEW – EXPLOIT AND EXPLORE



	Rocky Mountains*	Permian	Gulf Coast	Michigan	Mid-Continent	California	Total
Proved Reserves (Bcfe)	320.4	276.3	131.5	96.7	29.4	11.1	865.4
% of Total	37%	32%	15%	11%	4%	1%	100%
SEC PV-10, Pre-Tax ($ Millions)	604.5	603.1	364.1	198.5	53.1	28.3	1,851.6
% of Total	33%	33%	19%	11%	3%	1%	100%

*Includes one field in Canada with total estimated proved reserves of 5.8 Bcfe.

ROCKY MOUNTAIN REGION*

2004 Proved Reserves	320.4 Bcfe
% of Total Reserves	37%
2004 Net Wells	
Drilled / Successful	13.3 / 12.0
December 2004 Production	70.5 MMcfe/d
Total Net Acres	321,800

*Includes one field in Canada with total estimated proved reserves of 5.8 Bcfe.

Our Rocky Mountain operations are concentrated in the Williston Basin of North Dakota and Montana and the Greater Green River Basin of Wyoming. At year-end 2004, this is our largest region with 320.4 Bcfe, or 37% of our total proved reserves. Whiting is the sixth largest oil producer in North Dakota. In 2005 we are budgeting an investment of $73 million to drill or recomplete 139 gross wells in the Rocky Mountain region.

Whiting has added a significant amount of reserves in the Williston Basin through operational enhancements, exploitation and exploration drilling. Whiting entered the Basin with a producing property acquisition in August 2000 and expanded our position with the Big Stick Field acquisition in May 2002. At year-end 2004, net proved reserves total 172 Bcfe. The majority of recent reserve increases in the Basin are a result of operational enhancements and drilling in the Big Stick Field, the North Elkhorn Ranch Unit and exploration success in the Nisku A formation.

Big Stick Field

The Big Stick Field, which contains the Big Stick Madison Unit, is located in Billings County, North Dakota. Production within this field is primarily from a series of stacked, oil-saturated, porous dolomites within the Mission Canyon formation at an average depth of 9,400 feet. Additional deeper pay zones include the Duperow formation at 11,000 feet and the Red River formation at 12,700 feet.

We completed a detailed reservoir model study of the Mission Canyon formation in 2003. This study indicated that production to date accounts for only 18% of the estimated 276 million barrels of oil originally in place within the Mission Canyon horizon. In 2004, efforts were directed towards improving operating efficiency and increasing lift capacity. This program resulted in average 2004 daily production of 2,200 barrels of oil equivalent per day, an increase of 13% over 2003. Further development plans for the field include shooting a 3-D seismic survey and the drilling of additional vertical and horizontal wells.

Additional opportunities exist in the deeper Duperow and the Red River formations as proven by our fourth quarter 2003 discovery, the Egly #11-20 well. We believe that the Duperow and the Red River formations can be economically developed with vertical wells and existing infrastructure.

Horizontal Nisku Play

Whiting made a significant exploration discovery in 2004 in western Billings County, North Dakota in the Nisku A formation. In the third quarter of 2004, we re-entered the MOI Stillwater 21-23H well bore and drilled a 1,848 foot horizontal lateral in the Nisku A formation. The well had an initial production rate of 397 barrels of oil per day and 256 Mcf of natural gas per day on a 25/64th-inch choke with 200 pounds per-square-inch flowing tubing pressure. After this exploration success, Whiting quickly ramped up activity in the area and by year-end 2004 drilled a total of 10 wells in this play. Of the 10 wells drilled by Whiting, nine were successfully completed. The remaining well delineated the productive area of the play and was temporarily abandoned.

Whiting's gross year-end 2004 production exit rate from the Nisku A wells totaled 1,626 barrels of oil and 1.0 MMcf per day. In this play Whiting has 33,000 prospective net acres in Billings and Golden Valley Counties, North Dakota. On the western side of the play, in Golden Valley County, several grassroots wells were drilled by other operators in 2004 with encouraging initial results. In Billings County, during 2005 Whiting is budgeting to re-enter 16 well bores and drill horizontal laterals. In Golden Valley County, we plan to drill up to nine grassroots horizontal wells.

The Nisku formation is a thin, (two to four-foot thick) dolomite zone. The Nisku A traps are gentle folds and closures related to carbonate bank buildups overlain by anhydrite or shaly seals covering the regional Billings Nose structure trend. Seals are anhydrite beds overlying the main reservoirs. Secondary sealing is caused by argillaceous carbonate beds or shales. The thin but large aerial extent of the Nisku coupled with the overlying anhydrite seals makes the Nisku an ideal horizontal drilling target.

Elkhorn Ranch Unit

Just eight miles north of the Big Stick Field, Whiting operates and owns a 60% working interest in the North Elkhorn Ranch Unit. The Unit produces oil from saturated, porous dolomites within the Mission Canyon formation. The average producing depth of these reservoirs is 9,500 feet. Additional deeper pay zones include the Duperow formation at 11,300 feet and the Red River formation at 13,100 feet.

We are developing North Elkhorn on 160-acre spacing. In 2004, operational improvements allowed us to keep production essentially flat. In 2004, gross production averaged 1,100 barrels of oil equivalent per day as compared to 2003 gross production of 1,120 barrels of oil equivalent per day. Development opportunities are similar to the Big Stick Field, and consist of a mixture of new vertical and horizontal infill wells as well as some horizontal re-entry wells.

Siberia Ridge

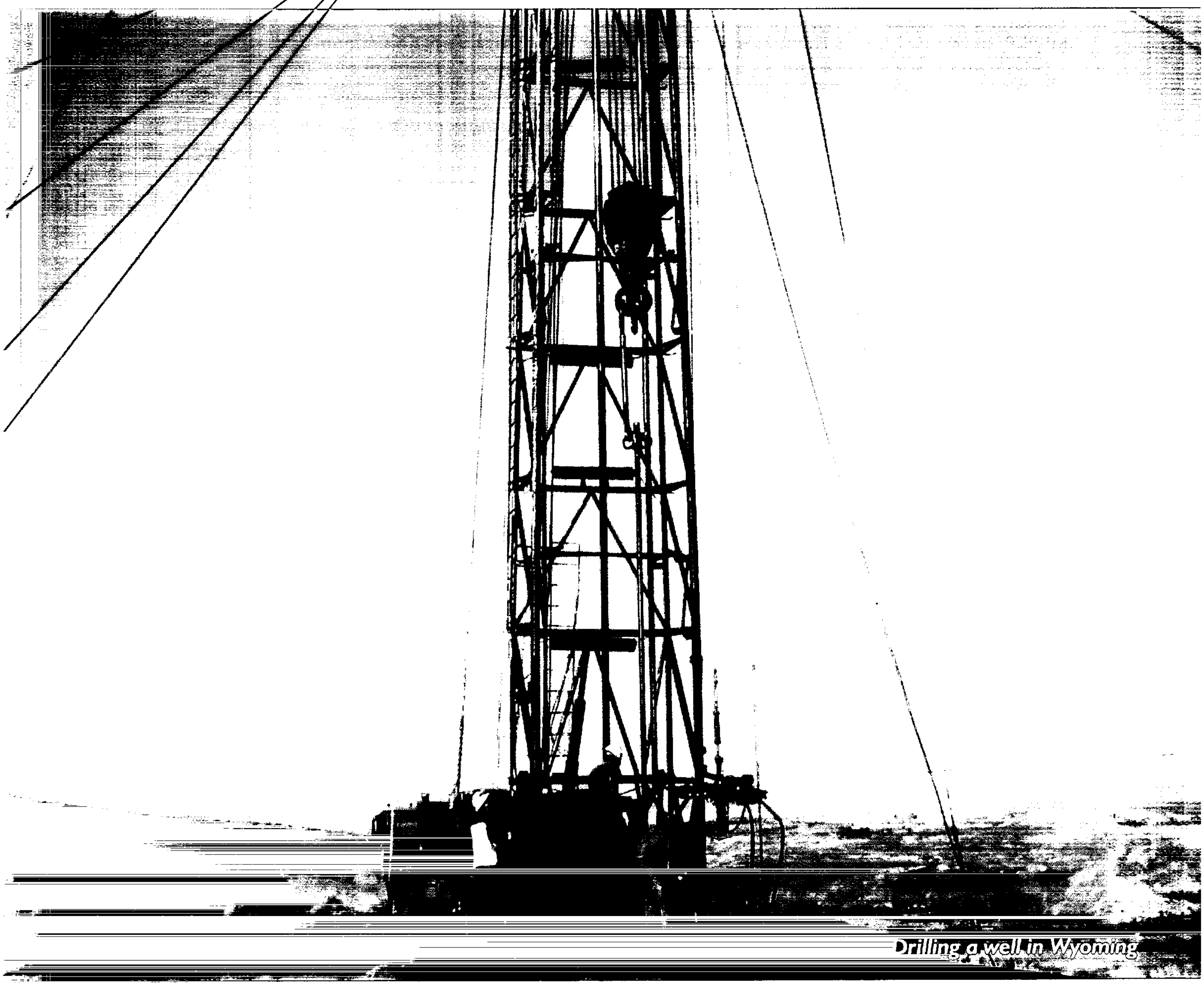
In southwestern Wyoming in the Greater Green River Basin, the Company, through the 2004 Equity Oil Company acquisition established a position in a multi-well, low-risk resource play in the Siberia Ridge Field in Sweetwater County. The primary target in the field is the Cretaceous-Almond formation at a depth of 10,500 feet. Whiting has more than 2,200 gross (1,580 net) undeveloped acres in this play with a working interest averaging between 50% to 100%. In 2004, the field was down-spaced to allow two wells per 160-acre spacing unit. In 2005, Whiting is planning 15 wells to be drilled in Siberia Ridge.

PERMIAN REGION

2004 Proved Reserves	276.3 Bcfe
% of Total Reserves	32%
2004 Net Wells Drilled / Successful	3.4 / 3.4
December 2004 Production	41.6 MMcfe/d
Total Net Acres	40,000

Whiting's Permian Basin region includes its properties in eastern New Mexico and western Texas. The Permian Basin represents the Company's second largest region, accounting for 32% of total proved reserves, or 276.3 Bcfe. In December of 2004, the area produced 41.6 MMcfe per day, or 22% of Whiting's total daily output. In September 2004, Whiting significantly increased its operations in the Permian Basin by completing a $345 million acquisition

OUR CONTINUED FOCUS IS TO INCREASE SHAREHOLDER VALUE BY INVESTING IN LONG-LIVED OIL AND GAS PROJECTS WITH ATTRACTIVE RATES OF RETURN ON CAPITAL EMPLOYED.



Drilling a well in Wyoming

of 17 fields. At the time of acquisition the properties were producing 38 MMcfe per day (approximately 72% operated) with estimated proved reserves of 251.1 Bcfe, resulting in an acquisition cost for these properties of $1.37 per Mcfe.

Nearly three-quarters of the long-lived Permian Basin reserve value Whiting acquired is concentrated in several key fields including Parkway, Would Have, Signal Peak, Keystone and the DEB Field. The largest of these fields are discussed below. They contain significant potential for exploitation, exploration and secondary recovery projects. In 2005 Whiting is budgeting development spending of $35 million to drill 129 gross wells and perform a number of workovers and recompletions in the Permian Basin.

Parkway Field

At Parkway Field where Whiting owns a non-operated 62% average working interest, production continues to increase from the secondary recovery waterflood project. In 2004, several infield wells were drilled with encouraging initial production rates in excess of 250 barrels of oil per day. In December 2004, gross daily field production averaged 1,786 barrels equivalent per day, 910 barrels equivalent per day net to Whiting. In 2005 Whiting expects to participate in an infill drilling program converting the field from a five spot flood pattern to a nine spot pattern.

Would Have Field

Whiting operates the Would Have Field and owns an 86% average working interest. The field has infill and step-out potential in the Clear Fork formation. Additional drilling potential exists in the Dillard Limestone as a result of a 2004 exploratory success. A waterflood was initiated in the western half of the field in May 2004 and efforts are underway to expand the flood to the eastern portion of the field. The Would Have property is covered by proprietary 3-D seismic data. We believe that utilization of this 3-D dataset has led to the efficient development and delineation of the field.

Signal Peak Field

The Signal Peak Field, where Whiting owns an operated 75% average working interest, has a significant number of natural gas exploitation drilling locations in the Wolfcamp formation. In December 2004 the field averaged 5.3 MMcfe per day of production net to Whiting. In 2005, Whiting is planning an active drilling program to evaluate the field's Wolfcamp potential.

GULF COAST REGION

2004 Proved Reserves	131.5 Bcfe
% of Total Reserves	15%
2004 Net Wells Drilled / Successful	22.4 / 20.8
December 2004 Production	47.2 MMcfe/d
Total Net Acres	69,900

The Gulf Coast represents Whiting's third largest region, accounting for 15% of total proved reserves, or 131.5 Bcfe. In December 2004, the area produced 47.2 MMcfe per day, or 25% of Whiting's total daily output. The region offers Whiting many multi-pay prospects targeting the Yegua, Edwards, Wilcox, Vicksburg, Frio and Sligo formations. In 2005 Whiting is budgeting development spending of $29 million to drill approximately 36 gross wells in the Gulf Coast area.

Stuart City Reef Trend

In June 2001, Whiting acquired 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

Pump jacks silently work to produce oil in Wyoming from the Frio, Yegua, Edwards, Wilcox, and Sligo formations at depths between 7,000 and 16,000 feet.

In 2004, Whiting had an active drilling program in the Edwards Lime and Wilcox formations drilling a total of nine wells. The Company drilled five horizontal Edwards Limestone wells in the Kawitt and Yokum Fields located in Dewitt and Karnes Counties, Texas. The wells are drilled horizontally at 14,000 feet with bottom-hole temperatures at or above 350 degrees. Two of these wells, the Julia Mott #6H (88% working interest) and the Rhodes Trust #3H (100% working interest), had combined initial production rates over 6.4 MMcfe per day. Two wells are being re-worked and one well was abandoned.

Whiting continued to have success in the Wilcox formation in this area. Following the fourth quarter 2003 Rhodes Trust #2 discovery, Whiting drilled three additional successful Wilcox wells in 2004. These three wells were producing at a gross combined 3.1 MMcfe per day at year end 2004.

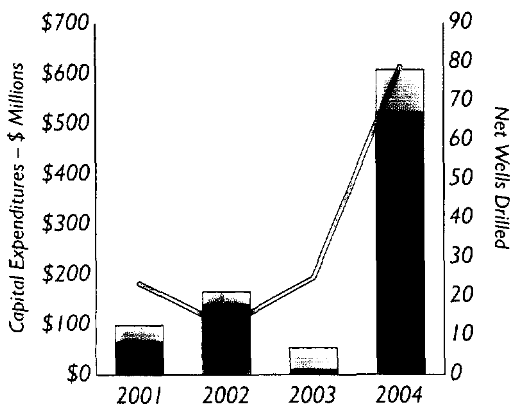
The 2004 drilling program resulted in a Stuart City Reef Trend production increase of 10% over 2003. In 2005 Whiting expects to continue an active program by drilling 18 wells. These will be a combination of horizontal and vertical wells.

Vicksburg Trend

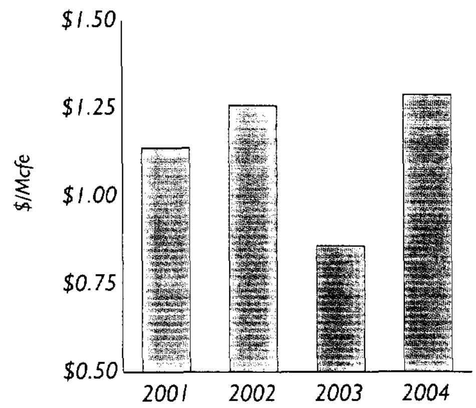
Whiting's holdings in the Vicksburg and Frio Trends are situated in four fields: Agua Dulce, Triple A, South Midway, and East White Point located in Nueces and San Patricio Counties, Texas. In 2004, Whiting drilled two wells in Agua Dulce Field and has significant ongoing operations. Four wells are scheduled to be drilled in this field in 2005.

Production in the Agua Dulce Field is from a series of highly faulted over-pressured sandstones within the Vicksburg formation at depths ranging from 8,000 to 10,000 feet. Three D seismic data aids our drilling at Agua Dulce. Each wellbore in our drilling program is designed to access several natural gas-charged reservoir sands. These sands are then fracture stimulated and simultaneously produced.

CAPITAL EXPENDITURES



FINDING, DEVELOPMENT & ACQUISITION COST



MICHIGAN REGION

2004 Proved Reserves	96.7 Bcfe
% of Total Reserves	11%
2004 Net Wells Drilled / Successful	38.1 / 37.1
December 2004 Production	20.0 MMcfe/d
Total Net Acres	62,500

Michigan represents Whiting's fourth largest region, accounting for 11% of total proved reserves, or 96.7 Bcfe. The area produced 20 MMcfe per day on average in December 2004, or 11% of Whiting's total daily output. Whiting's 2005 capital expenditures budget allocates $10 million, to drill approximately 36 gross wells in Michigan.

Production in Michigan can be divided into two groups. The majority of the reserves are in non-operated Antrim Shale wells. 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.

Antrim Production

In northern Michigan, Whiting owns an interest in 57 multi-well Antrim Shale natural gas projects with proved reserves and additional unproved potential. Approximately ten of our Antrim Shale projects have significant remaining development potential. In 2004 Whiting participated in the drilling and completion of 50 Antrim Shale wells. Whiting's 39% working interest generated average net production from the Antrim Shale in 2004 of 13 MMcf per day.

Conventional Production

Whiting's conventional production is primarily from the Prairie du Chien, Glenwood and Trenton Black River formations located in central Michigan. Whiting operates seven fields and owns an interest in another 13 fields in this area. The Prairie du Chien Fields produce natural gas and retrograde condensate from various intervals within a 500 to 800 foot thick sequence of sandstones and dolomitic sandstones at a depth of 10,500 to 11,200 feet. The low permeability and heterogeneous character of the Prairie du Chien reservoirs has resulted in low recovery of the original natural gas in place from the existing wells. This provides us with significant opportunities for increased recovery through infill and horizontal drilling.

BOARD OF DIRECTORS

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. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has over 30 years of experience in the oil and natural gas industry. Mr. Volker has a degree in finance from the University of Denver, an MBA from the University of Colorado and has completed H. K. VanPoolen and Associates' course of study in reservoir engineering.

Thomas L. Aller has been a director since 1997. He is currently President of Interstate Power and Light Co., an Alliant Energy company. He served as President of Alliant Energy Investments, Inc. from April 1998 and was later appointed interim Executive Vice President–Energy Delivery of Alliant Energy in September 2003. From 1993 to 1998, he served as Vice President of IES Investments Inc. He received his Bachelor's Degree in political science from Creighton University and his Master's Degree in municipal administration from the University of Iowa.

Graydon D. Hubbard has been a director since September 2003. He is a retired certified public accountant and was a partner of Arthur Andersen LLP in its Denver office for more than five years prior to his retirement in November 1989. Since 1991 he has served as a director of Hathaway Corporation, a company engaged in the business of designing, manufacturing and selling motion control products. Mr. Hubbard is also an author. He received his Bachelor's Degree in accounting from the University of Colorado.

J. B. Ladd has been a director since our inception in January of 1980. He is an independent oil and natural gas operator with offices in Los Angeles, California and Denver, Colorado. He has over 50 years of experience in the oil and natural gas industry working for Texaco and Consolidated Oil and Gas, Inc. and as an independent oil and natural gas operator. He founded Ladd Petroleum Corporation in 1968, which was merged into Utah International in 1973 and later merged into General Electric Company in 1976. Mr. Ladd received a degree in petroleum engineering from the University of Kansas.

Kenneth R. Whiting is our founder and has been a director of Whiting since our inception in January of 1980. He was President and Chief Executive Officer from our inception until 1993, when he was appointed Vice President of International Business for IES Diversified, our former parent company's predecessor. From 1978 to late 1979 he served as President of Webb Resources, Inc. He has many years of experience in the oil and natural gas industry, including his position as Executive Vice President of Ladd Petroleum Corporation. He was a partner and associate with Holme Roberts & Owen, Attorneys at Law. Mr. Whiting received his Bachelor's Degree in business from the University of Colorado and his J.D. from the University of Denver.

Palmer L. Moe has served as a director of Whiting Petroleum Corporation since October 2004. He is Managing Director of Kronkosky Charitable Foundation in San Antonio, Texas, a position he has held since 1997. Mr. Moe is a certified public accountant and was a partner of Arthur Anderson & Co. in its San Antonio, Houston and Denver offices from 1965 to 1983. From 1983 until 1992, he served as President and Chief Operating Officer and a director of Valero Energy Corporation. He received his Bachelor's Degree in accounting from the University of Denver and completed the Senior Executive Development Course at the Alfred P. Sloan School of Management at the Massachusetts Institute of Technology.

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

FORM 10-K

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

For the fiscal year ended December 31, 2004

or

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

For the transition period from _____________ to _____________

Commission file number: 001-31899

WHITING PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**20-0098515** (I.R.S. Employer Identification No.)
1700 Broadway, Suite 2300 **Denver, Colorado** (Address of principal executive offices)	**80290-2300** (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 (Title of Class)	**New York Stock Exchange** (Name of each exchange on which registered)

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

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 [X] No [ ]

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes [X] No [ ]

Aggregate market value of the voting stock held by nonaffiliates of the registrant at June 30, 2004: $466,391,785.75

Number of shares of the registrant's common stock outstanding at February 15, 2005: 29,720,103 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2005 Annual Meeting of Stockholders are incorporated by reference into Part III.

TABLE OF CONTENTS

CERTAIN DEFINITIONS

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

We have included below the definitions for certain 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.

"Bcfe" One billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

"Bopd" Barrels of oil per day.

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

"horizontal re-entry well" A new well in which a pre-existing wellbore is used as the starting point of a new horizontal borehole. Drilling a horizontal re-entry well typically involves milling a hole in the casing of the pre-existing wellbore and drilling hundreds or thousands of feet from the pre-existing wellbore.

"Mcf" One thousand cubic feet of natural gas.

"Mcf/d" One Mcf per day.

"Mcfe" One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

"Mcfe/d" One Mcfe per day.

"MMBbls" millions of barrels of oil or other liquid hydrocarbons.

"MMBtu" One million British Thermal Units.

"MMcf" One million cubic feet of natural gas.

"MMcf/d" One MMcf per day.

"MMcfe" One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

"MMcfe/d" One MMcfe per day.

"PDNP" Proved developed nonproducing.

"PDP" Proved developed producing.

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

"PUD" Proved undeveloped.

"pre-tax PV10%" The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with 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%.

"reservoir" A porous and permeable underground formation containing a natural accumulation of producible 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 oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

PART I

Item 1. Business

Overview

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Rocky Mountains, Permian Basin, Gulf Coast, Michigan, Mid-Continent and California regions of the United States. Our focus is on pursuing growth projects that we believe will generate attractive rates of return and maintaining a balanced portfolio of lower risk, long-lived oil and natural gas properties that provide stable cash flows.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through both property acquisitions and exploitation activities. As of January 1, 2005, our estimated proved reserves totaled 865.4 Bcfe, of which 70.1% were classified as proved developed. These estimated reserves had a pre-tax PV10% value of approximately $1.85 billion, of which approximately 70% came from properties located in three states: Texas, North Dakota and Michigan. During 2004, we invested $606.9 million in acquisition, exploration and development activities, including $79.4 million for the drilling of 169 gross (79 net) wells. Of these new wells, 160 resulted in productive completions and 9 were unsuccessful, yielding a 95% success rate. We have budgeted approximately $130 million to $150 million for development drilling expenditures in 2005. Although we have no specific budget for acquisitions, we will also seek property acquisition opportunities that meet our rate of return criteria and complement our existing core properties.

As of January 1, 2005, we had a balanced portfolio of oil and natural gas reserves, with approximately 39.3% of our proved reserves consisting of natural gas and approximately 60.7% consisting of oil. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of proved reserves to annual production (based on December 2004 production) of approximately 12.6 years.

The following table summarizes our estimated proved reserves and pre-tax PV10% value within our core areas as of January 1, 2005 and our estimated December 2004 average daily production.

	Proved Reserves					
Core Area	**Oil (MMBbl)**	**Natural Gas (Bcf)**	**Total (Bcfe)**	**% Natural Gas**	**Pre-Tax PV10% Value (In millions)**	**December 2004 Average Daily Production (MMcfe)**
Rocky Mountains[1]	42.9	62.9	320.4	19.6%	$ 604.5	70.5
Permian Basin	36.8	55.3	276.3	20.0%	$ 603.1	41.6
Gulf Coast	4.0	107.9	131.5	82.0%	$ 364.1	47.2
Michigan	1.8	85.7	96.7	88.7%	$ 198.5	20.0
Mid-Continent	2.1	17.0	29.4	57.7%	$ 53.1	5.4
California	0.0	11.1	11.1	100.0%	$ 28.3	3.3
Total	87.6	339.9	865.4	39.3%	$ 1,851.6	188.0

(1) Includes one field in Canada with total estimated proved reserves of 5.8 Bcfe and a pre-tax PV10% value of $13.2 million.

2004 Acquisitions

During 2004, we completed seven separate acquisitions of producing properties with a combined purchase price of $535.1 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 436.1 Bcfe, representing an average cost of approximately $1.23 per Mcfe of estimated proved reserves. We will continue to seek property acquisition opportunities that complement our existing core properties. We believe that our exploitation and acquisition expertise and our drilling inventory, together with our operating experience and efficient cost structure, provide us with the potential to continue our growth. The following table summarizes certain information about the purchase price, estimated proved reserves and pre-tax PV10% value as of the effective dates of acquisition for each of the seven acquisitions that we completed in 2004.

	Purchase Prices (In millions)		Proved Reserves Oil (MMBbl)	Natural Gas (Bcf)	Total (Bcfe)	% Natural Gas	% Developed
Permian Basin Properties[1]	$	345.0	34.3	45.1	251.1	18%	59%
Equity Oil Company[2]	$	72.6	9.9	28.1	87.7	32%	79%
Colorado/ Wyoming[3]	$	44.2	3.1	21.3	39.8	54%	82%
Wyoming/Utah[4]	$	35.0	3.4	10.7	30.8	35%	92%
Louisiana/Texas[5]	$	19.3	0.2	10.9	12.0	91%	63%
Mississippi[6]	$	12.0	1.5	1.6	10.6	15%	79%
Additional Permian Basin[7]	$	7.0	0.6	0.4	4.1	9%	17%
Total Acquisitions	$	535.1	53.0	118.1	436.1	27%	68%

(1) Revenues and volumes are included in our results beginning September 23, 2004.

(2) Equity's results of operations and volumes are included in our results beginning July 20, 2004.

(3) Revenues and volumes are included in our results beginning August 13, 2004.

(4) Revenues and volumes are included in our results beginning September 30, 2004.

(5) Revenues and volumes are included in our results beginning August 16, 2004.

(6) Revenues and volumes are included in our results beginning November 3, 2004.

(7) Revenues and volumes are included in our results beginning December 31, 2004.

Permian Basin Properties

On September 23, 2004, we 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 our bank credit agreement. Based on the purchase price and estimated proved reserves of 251.1 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.37 per Mcfe of estimated proved reserves.

Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our 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 87.7 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $0.83 per Mcfe of estimated proved reserves.

Other Cash Acquisitions of Properties

Colorado and Wyoming Properties. On August 13, 2004, we acquired interests in four producing oil and gas fields in Colorado and Wyoming. The purchase price was $44.2 million in cash and was funded under our bank credit agreement. Based on the purchase price of $44.2 million and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.11 per Mcfe of estimated proved reserves.

Wyoming and Utah Properties. On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah. The purchase price was $35.0 million in cash and was funded under our bank credit agreement. Based on the purchase price of $35.0 million and estimated proved reserves of 30.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.14 per Mcfe of estimated proved reserves.

Louisiana and South Texas Properties. On August 16, 2004, we acquired interests in five fields in Louisiana and South Texas. The purchase price was $19.3 million in cash and was funded under our bank credit agreement. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.61 per Mcfe of estimated proved reserves.

Mississippi Properties. On November 3, 2004, we acquired an interest in the Lake Como Field in Mississippi. The purchase price was $12.0 million in cash and was funded under our bank credit agreement. Based on the purchase price of $12.0 million and estimated proved reserves of 10.6 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.43 per Mcfe of estimated proved reserves.

Additional Permian Basin Interest. On December 31, 2004, we 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 our bank credit agreement. Based on the purchase price and estimated proved reserves of 4.1 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.72 per Mcfe of estimated proved reserves.

Business Strategy

Our goal is to increase stockholder value by investing in oil and gas projects with attractive rates of return on capital employed. We plan to achieve this goal by exploiting and developing our existing oil and natural gas properties and pursuing acquisitions of additional properties. Specifically, we have focused, and plan to continue to focus, on the following:

Developing and Exploiting Existing Properties. We believe that there is significant value to be created by drilling the numerous identified undeveloped opportunities on our properties. As of January 1, 2005, we owned interests in a total of 752,000 gross (300,400 net) developed acres. In addition, as of December 31, 2004, we owned interests in approximately 608,800 gross (315,700 net) undeveloped acres that contain many exploitation opportunities. During the year ending December 31, 2004, we invested $79.4 million to drill 169 gross (79 net) wells. Of these new wells, 95% resulted in productive completions. For 2005, we have budgeted $130 million to $150 million for the further exploration and development of our properties.

Pursuing Profitable Acquisitions. We have pursued and intend to continue to pursue acquisitions of properties that we believe to have exploitation and development potential comparable to our existing inventory of drilling locations. We have developed and refined an acquisition program designed to increase reserves and complement our existing core properties. We have an experienced team of management, engineering and geoscience professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties. During 2004, we completed seven separate acquisitions of producing properties with a combined purchase price of $535.1 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 436.1 Bcfe, resulting in an aggregate cost of $1.23 per Mcfe of estimated proved reserves. To secure attractive realized commodity prices on a portion of our producing volumes, we periodically enter into derivative contracts, typically no-cost collars.

Focusing on High Return Operated and Non-Operated Properties. We have historically acquired operated as well as 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 complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent they meet our return criteria and further our growth strategy.

Competitive Strengths

We believe that our key competitive strengths lie in our diversified asset base, our experienced management and technical team and our commitment to efficient utilization of new technologies.

Diversified Asset Base. As of January 1, 2005, we had interests in 6,970 productive wells across our six core geographical areas. This property base, as well as our continuing business strategy of acquiring and developing properties in our core operating areas, presents us with a large number of opportunities for successful development and exploitation and additional acquisitions.

Experienced Management Team. Our management team averages over 25 years of experience in the oil and natural 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 20 years of experience in the evaluation, acquisition and operational assimilation of oil and natural 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 961 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, such as the WellView® software system, 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 development activities.

Proved Reserves

Our estimated proved reserves as of January 1, 2005 are summarized in the table below.

	Oil (MBbl)	Natural Gas (MMcf)	Total (Bcfe)	% of Total Proved	Pre-tax PV-10% (In thousands)	Future Capital Expenditures (In thousands)
Rocky Mountains[1]:						
PDP	33,099	36,899	235.5	73.5%	$ 449,450	$ 1,954
PDNP	1,304	588	8.4	2.6%	10,501	2,556
PUD	8,514	25,415	76.5	23.9%	144,547	68,411
Total Proved	42,917	62,902	320.4	100%	$ 604,498	$ 72,921
Permian Basin:						
PDP	18,768	37,591	150.2	54.4%	$ 317,464	$ 359
PDNP	1,795	1,203	12.0	4.3%	34,119	2,186
PUD	16,268	16,469	114.1	41.3%	251,526	71,447
Total Proved	36,831	55,263	276.3	100%	$ 603,109	$ 73,992
Gulf Coast:						
PDP	2,428	59,446	74.0	56.3%	$ 221,754	$ 1,894
PDNP	265	10,133	11.7	8.9%	32,982	2,355
PUD	1,249	38,290	45.8	34.8%	109,363	50,980
Total Proved	3,942	107,869	131.5	100%	$ 364,099	$ 55,229
Michigan:						
PDP	733	66,478	70.9	73.3%	$ 125,807	$ —
PDNP	168	2,566	3.6	3.7%	12,788	780
PUD	922	16,747	22.2	23.0%	59,841	12,420
Total Proved	1,823	85,791	96.7	100%	$ 198,436	$ 13,200
Mid-Continent:						
PDP	2,060	16,207	28.5	97.1%	$ 52,295	$ —
PDNP	5	734	0.8	2.6%	613	610
PUD	9	37	0.1	0.3%	239	161
Total Proved	2,074	16,978	29.4	100%	$ 53,147	$ 771
California:						
PDP	—	5,716	5.7	51.7%	$ 15,924	$ —
PDNP	—	5,102	5.1	46.2%	11,819	370
PUD	—	235	.3	2.1%	562	380
Total Proved	—	11,053	11.1	100%	$ 28,305	$ 750
Total Corporate:						
PDP	57,088	222,337	564.8	65.3%	$ 1,182,694	$ 4,207
PDNP	3,537	20,326	41.6	4.8%	102,822	8,857
PUD	26,962	97,193	259.0	29.9%	566,078	203,799
Total Proved	87,587	339,856	865.4	100%	$ 1,851,594	$ 216,863

[1] Includes one field in Canada with total estimated proved reserves of 5.8 Bcfe and a pre-tax PV10% value of $13.2 million.

Marketing and Major Customers

We principally sell our oil and natural 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 natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For fiscal year 2004, no single customer was responsible for generating 10% or more of our total oil and natural gas sales.

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 interferes 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 natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural 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 natural gas industry.

Regulation

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in inter state commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the Federal Energy Regulatory Commission, or the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act. The Decontrol Act removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect. While most major aspects of Order No. 637 have been upheld on judicial review, certain issues such as capacity segmentation and right of first refusal are pending further consideration by the FERC. We cannot predict what action FERC will take on these matters in the future, or whether the FERC's actions will survive further judicial review.

The Outer Continental Shelf Lands Act, which the FERC implements as to transportation and pipeline issues, 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. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. 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 transportation rates for oil 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. On remand, 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 natural 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 natural gas properties, the establishment of maximum allowable rates of production from oil and natural 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 natural 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, natural 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 natural gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and natural 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 natural 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 natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Regulations

General. Our oil and natural 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, also referred to as 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 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 natural 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 adversely affect our operations and financial position, as well as those of the oil and natural 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 natural 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 natural 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 million while the liability limit for offshore facilities is the payment of all removal costs plus up to $75 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 million ($10 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 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 natural 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, 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. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced water, sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater 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 furtherance of the Clean Water Act, 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, if necessary to ensure compliance, in February 2006 with the implementation of such amended plans in August 2006. 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 natural 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 natural 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, 2004, we had 171 full-time employees, including 12 senior level geoscientists and 17 petroleum engineers. Our employees are not represented by any labor union. 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 with 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 2. Properties

Summary of Oil and Natural Gas Properties and Projects

Rocky Mountain Region

Our Rocky Mountain operations include assets in the states of North Dakota, Montana, Colorado, Utah, Wyoming and in the Canadian province of Alberta. As of January 1, 2005, our proved reserves in the Rocky Mountain region were 320.4 Bcfe (80.4% oil), which accounted for 37.0% of our total estimated proved reserves. The majority of our reserves in the Rocky Mountain region are in North Dakota and Wyoming. Approximately 52% of the proved reserves of our Rocky Mountain operations are related to assets in North Dakota. Our Canadian assets consist solely of our 50% working interest in the Cessford Field located in southern Alberta, with total proved reserves of 5.8 Bcfe and a pre-tax PV10% value of $13.2 million.

Big Stick (Madison) Unit. The Big Stick Field, which contains the Big Stick (Madison) Unit, is located in Billings County, North Dakota and produces from a series of stacked, oil saturated, porous dolomites within the Mission Canyon Formation at an average depth of 9,400 feet. We operate this unit and own a 62% working interest. We completed a detailed reservoir model study of the Mission Canyon Formation in 2003. Specifically, this study indicated that production to date accounts for only 18% of the estimated 276 MMBbls of oil originally in place within the Mission Canyon horizon. In 2004, efforts were directed towards improving operating efficiency and increasing lift capacity. This program resulted in 2004 daily equivalent oil production to average 2,100 barrels of oil equivalent per day, an increase of 10% over 2003. Further development plans for the field include shooting a 3-D seismic survey over the field and the drilling of additional vertical and horizontal wells. Additional opportunities exist in the deeper Duperow and the Red River formations. As proven by our fourth quarter 2003 discovery, the Egly #11-20 well, we believe that the Duperow and the Red River Formations can be economically developed with vertical wells and existing infrastructure.

Nisku A Drilling Program. We made a significant exploration discovery in 2004 in western Billings County, North Dakota in the Nisku A. In the third quarter of 2004, we re-entered the MOI Stillwater 21-23H well bore and drilled a 2,690 foot horizontal lateral in the Nisku A formation. The well had an initial production rate of 397 barrels of oil per day and 256 Mcf of gas per day on a 25/64th-inch choke with 200 pounds per square inch flowing tubing pressure. After this exploration success, we quickly ramped up activity in the area and by the end of 2004, we had drilled a total of ten wells in this play. Of the ten wells, nine were successfully completed. The remaining well, which was drilled on the edge of the expected productive area to help delineate the productive area of the play, was abandoned. Our gross year end 2004 production exit rate from the Nisku A wells totaled 1,630 bopd and 1.0 MMcf/d. During 2004 we participated in (but did not operate) the drilling of several grassroots wells on the western side of the play with encouraging initial results. In 2005, we plan to continue drilling a combination of casing-exit and grass-roots lateral wells on our Nisku A acreage.

The "A" zone of the Nisku Formation is a thin, two to four foot dolomite bed encased between two impermeable anhydrite beds creating a regional stratigraphic trap that is present over more than 100 square miles. These geologic conditions make the Nisku A an ideal horizontal drilling candidate. We currently hold 33,000 prospective net acres in Billings and Golden Valley Counties, North Dakota.

Green River Basin—Siberia Ridge. In Southwestern Wyoming in the Green River Basin, we established a position in a multi-well low risk resource play in the Siberia Ridge Field in Sweetwater County through our 2004 acquisition of Equity Oil Company. The primary target in the field is the Cretaceous Almond Formation at a depth of 10,500 feet. We hold over 2,200 gross (1,580 net) undeveloped acres in this play with a working interest ranging between 50 and 100 percent. In 2004, our acreage in the field was down-spaced to allow a second well on each 160 acre spacing unit. In 2005, we plan to drill up to 15 wells in Siberia Ridge.

Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of January 1, 2005, the Permian Basin region contributed 276.3 Bcfe (80% crude oil) of net proved reserves to our portfolio of operations, which represents 31.9% of our total estimated proved reserves. Approximately 84% of the proved reserves of our Permian Basin operations are related to properties in Texas.

Parkway (Delaware) Unit. We own a 61.6% non-operated working interest in the Parkway (Delaware) Unit, which is concentrated on 920 gross acres in Eddy County, New Mexico. December 2004 net production averaged 840 bopd and 420 Mcf/d of natural gas. An enhanced oil recovery project currently underway involves drilling eight additional producing wells designed to convert the current waterflood configuration from a five-spot to a nine-spot pattern.

Would Have Field. We own an approximately 86% operated working interest in the Would Have Field in Howard County, Texas, with net December 2004 production of 1,740 bopd and 1,470 Mcf/d of natural gas from 49 wells. Discovered in 2001, this field produces from two sub-units of the Clearfork Formation, the Would Have and the Dillard Limestones. A waterflood was initiated in the western half of the field in May 2004 and efforts are underway to expand the flood to the eastern portion of the field. Our drilling program in the Would Have field benefits from the use of proprietary 3-D seismic data which has a direct impact on our ability to define areas of reservoir development. The Would Have Field is only partially developed, with both infill and step-out locations remaining to be drilled.

Signal Peak Field. As of December 31, 2004, our Signal Peak property was contributing 244 bopd and 5.2 MMcf/d net to our interest. We own an average working interest of 75% in the 84 wells we operate, and 25% working interest in 24 wells operated by others. The Signal Peak Field produces from the Wolfcamp Formation, with behind-pipe Clearfork potential identified in several wells. We are currently conducting a selective development drilling program and are evaluating the potential for enhanced gas recovery by increased density well spacing.

Keystone Field. Our 100% working interest in the Keystone Field provides both substantial production (360 bopd and 1.4 Mcf/d of natural gas, net based on December 2004 production rates) and a large portfolio of additional exploration and development opportunities. The property covers a surface area of 7,260 acres in Winkler County, Texas. Most current production comes from the Clearfork Formation, with additional production from the Wichita-Albany, Wolfcamp, Devonian, Silurian, McKee and Ellenburger. The abundance of producing horizons in the Keystone Field has resulted in several behind-pipe recompletion opportunities. Current drilling at the Keystone Field is targeting the shallow Wichita-Albany Formation. We believe that development of deeper pay horizons will benefit from a 3-D seismic survey which we plan to conduct this year.

DEB Field. We own a 100% working interest in the DEB Field that covers 740 acres in Gaines County, Texas and produces 880 bopd and 55 Mcf/d net, based on December 2004 production rates from nine wells. The Wolfcamp reservoir is subdivided into two productive intervals, the A and the B, that both produce and are commingled in several wells. Current injection into the Wolfcamp is approximately 19,800 barrels of water per day and oil production in this long-life property has remained relatively flat for many years. Modifications have recently been completed increasing the fluid handling capability of the facilities. This will allow submersible pumps with increased capacity to be installed. We have identified additional drilling opportunities which we plan to pursue in 2005.

Gulf Coast Region

Our Gulf Coast operations include assets located in Texas, Louisiana and Mississippi. As of January 1, 2005, the Gulf Coast region contributed 131.5 Bcfe (82% natural gas) of net proved reserves to our portfolio of operations, which represented 15.2% of our total net proved reserves. Approximately 78% of the proved reserves of our Gulf Coast operations are related to properties in Texas.

Stuart City Reef Trend. In June 2001, we acquired 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 2004, we had an active drilling program in the Edwards Limestone and Wilcox Formation, drilling a total of nine wells. We drilled five horizontal Edwards Limestone wells in the Kawitt and Yoakum Fields located in Dewitt and Karnes, Counties Texas, with varying results. These technically challenging wells are drilled horizontally at 14,000 feet with bottom hole temperatures at or above 350 degrees Fahrenheit. Two of the wells, the Julia Mott #6H (81% working interest) and the Rhodes Trust #3H (100% working interest), had a combined initial production rate over 6.4 MMcfe/d.

Two of these wells encountered temperature-related mechanical problems and were temporarily abandoned, and one was a dry hole. We believe that a significant gas resource is present in our Edwards Limestone reservoirs and are working to resolve technical problems encountered in these wells before proceeding in 2005.

Leveraging our 2003 drilling success in the Rhodes Trust #2H discovery, we began a development drilling program targeting the Wilcox Formation at 10,000 feet in the third quarter 2004. During the remainder of 2004, we drilled four Wilcox wells which were producing at a combined rate of 3.6 MMcfe/d net to our interest at December 31, 2004. We expect to continue an active Wilcox drilling program in 2005 with a combination of up to 18 horizontal and vertical wells.

Vicksburg Trend. Our holdings in the Vicksburg and Frio Trends are concentrated in the Agua Dulce, Triple A, South Midway, and East White Point fields in Nueces and San Patricio Counties, Texas. We have significant ongoing operations in both Agua Dulce and South Midway fields where we drilled or participated in eight new wells or recompletions. These operations resulted in production increases of 6.1 MMcfe/d and 319 bopd net to our interest.

Michigan Region

As of January 1, 2005, Michigan accounted for 11.2% of our total estimated proved reserves, or 96.7 Bcfe. In December 2004, the area produced 20.0 MMcfe per day, or 10.6% of our total daily output. Production in Michigan can be divided into two groups. The majority of the reserves are in non-operated Antrim Shale wells. 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 Stoney Point natural gas processing plants. These plants are in excellent 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 57 multi-well Antrim Shale natural gas projects with proved producing reserves and ongoing development drilling. During 2004, we participated in the drilling and completion of 50 Antrim Shale wells. In 2005, we plan to continue to pursue the development drilling opportunities and work with one of the operators who has initiated a successful re-frac program.

Conventional Production. Our conventional production is primarily from the Prairie du Chien, Glenwood and Trenton Black River Formations located in central Michigan. We own interests in over 20 fields in this area, of which we operate seven.

The Prairie du Chien fields produce natural gas and retrograde condensate from various intervals within a 500 to 800 foot thick sequence of sandstones and dolomitic sandstones at a depth of 10,500 to 11,200 feet. The low permeability and heterogeneous character of the Prairie du Chien reservoirs has resulted in low recovery of the original natural gas in place from the existing wells, providing us with significant opportunities for increased recovery through infill and horizontal drilling. We plan to drill three wells early in 2005.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. As of January 1, 2005, the Mid-Continent region contributed 29.4 Bcfe (57.7% natural gas) of net proved reserves to our portfolio of operations, which represented 3.4% of total net proved reserves. The majority of the proved value within our Mid-Continent operations is related to properties in Oklahoma. The Oklahoma production is scattered throughout the state, with the single largest concentration being in the company-operated Putnam Oswego Unit, located in Dewey and Custer Counties in West-Central Oklahoma.

Our proved properties located in Arkansas are operated, and are primarily in two fields, the Magnolia Smackover Pool Unit and the Wesson Hogg Sand Unit. Both of these fields are mature pressure maintenance units.

California Region

As of January 1, 2005, our California operations contributed 11.1 Bcfe (100% natural gas) of net proved reserves to our portfolio of operations, which represented 1.3% of our total net proved reserves. Our assets in this region are located in the State of California, including an operated 100% working interest in 27 producing gas wells and associated leasehold primarily in the Todhunters Lake and Willow Slough Fields of Yolo County, California. We also own non-operated working interests in Colusa and Glenn Counties, California.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2004 by region (net acreage is our percentage ownership of gross acreage). Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountains	251,800	132,400	470,200	189,400	722,000	321,800
Permian Basin	99,900	15,100	32,400	24,900	132,300	40,000
Gulf Coast	161,400	61,900	9,500	8,000	170,900	69,900
Michigan	179,100	62,200	1,100	300	180,200	62,500
Mid-Continent	40,700	21,400	91,300	90,400	132,000	111,800
California	19,100	7,400	4,300	2,700	23,400	10,100
Total	752,000	300,400	608,800	315,700	1,360,800	616,100

Production History

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

	Year Ended December 31,		
	2004	2003	2002
Oil production (MMBbls)	3.7	2.6	2.3
Natural gas production (Bcf)	25.1	21.6	21.4
Total production (Bcfe)	47.0	37.2	35.2
Daily production (MMcfe/d)	128.5	101.8	96.4
Average sales prices:			
Natural gas (per Mcf)	$ 5.56	$ 4.78	$ 3.21
Effect of natural gas hedges on average price (per Mcf)	$ —	$ (0.30)	$ (0.01)
Natural gas net of hedging (per Mcf)	$ 5.56	$ 4.48	$ 3.20
Oil (per Bbl)	$ 38.72	$ 27.50	$ 23.35
Effect of oil hedges on average price (per Bbl)	$ (1.33)	$ (0.37)	$ (1.27)
Oil net of hedging (per Bbl)	$ 37.39	$ 27.13	$ 22.08
Per Mcfe data:			
Sales price (net of hedging)	$ 5.87	$ 4.50	$ 3.39
Lease operating expenses	$ 1.15	$ 1.16	$ 0.93
Production taxes	$ 0.36	$ 0.29	$ 0.21
Depreciation, depletion and amortization expense	$ 1.15	$ 1.11	$ 1.24
General and administrative expenses, net of reimbursements	$ 0.45	$ 0.34	$ 0.34

Productive Wells

The following table presents our ownership at December 31, 2004 in productive oil and natural 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
Rocky Mountains	1,617	421	282	80	1,899	501
Permian Basin	873	304	39	31	912	335
Gulf Coast	1,607	175	873	314	2,480	489
Michigan	80	58	978	364	1,058	422
Mid-Continent	348	148	205	85	553	233
California	—	—	68	41	68	41
Total	4,525	1,106	2,445	915	6,970	2,021

(1) 62 wells are multiple completions. These 62 wells contain a total of 131 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**
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
2003:						
Development	64	5	69	20.9	2.3	23.2
Exploratory	—	3	3	—	1.6	1.6
Total	64	8	72	20.9	3.9	24.8
2002:						
Development	24	8	32	8.1	4.1	12.2
Exploratory	—	1	1	—	0.2	0.2
Total	24	9	33	8.1	4.3	12.4

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 2004.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 15, 2005, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	58	Chairman, President and Chief Executive Officer
D. Sherwin Artus	67	Senior Vice President
James R. Casperson	57	Vice President of Finance and Chief Financial Officer
James T. Brown	52	Vice President, Operations
Bruce R. DeBoer	52	Vice President, General Counsel and Corporate Secretary
J. Douglas Lang	55	Vice President, Reservoir Engineering/Acquisitions
Patricia J. Miller	67	Vice President of Human Resources
David M. Seery	50	Vice President of Land
Mark R. Williams	48	Vice President, Exploration and Development
Michael J. Stevens	39	Controller and Treasurer

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

James J. Volker joined us in August 1983 as Vice President of Corporate Development and served in that position through April 1993. In March 1993, he became a contract consultant to us and served in that capacity until August 2000, at which time he became Executive Vice President and Chief Operating Officer. Mr. Volker was appointed President and Chief Executive Officer and a director in January 2002 and Chairman of the Board in January 2004. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has over thirty years of experience in the oil and natural 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.

D. Sherwin Artus joined us in January 1989 as Vice President of Operations and became Executive Vice President and Chief Operating Officer in July 1999. In January 2000, he was appointed President and Chief Executive Officer and a director. In January 2002, he became Senior Vice President. He has been in the oil and natural gas business for over forty years. Mr. Artus holds a Bachelor's Degree in geologic engineering and a Master's Degree in mining engineering from the South Dakota School of Mines and Technology.

James R. Casperson joined us in February 2000 as Vice President of Finance and Chief Financial Officer. From June 1985 to February 2000, he was founder and president of Casperson, Inc., a private consulting firm. Mr. Casperson has twenty-six years of financial and operational experience in the oil and natural gas industry. Mr. Casperson holds a Bachelor's Degree from Texas Tech University. Effective March 1, 2005, Mr. Casperson will resign as Vice President of Finance and Chief Financial Officer.

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 thirty years of oil and natural 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 a MBA from the University of Denver.

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 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-four 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.

Mark R. Williams joined us in December 1983 as Exploration Geologist, becoming Vice President of Exploration and Development in December 1999. He has twenty-three years of experience in the oil and natural 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.

Michael J. Stevens joined us in May 2001 as Controller, and became Treasurer in January 2002. 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 natural 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. Effective March 1, 2005, Mr. Stevens will be appointed as Vice President and Chief Financial Officer.

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.

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 has been traded on the New York Stock Exchange under the symbol "WLL" since our initial public offering on November 20, 2003. 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, 2004				
Fourth Quarter (Ended December 31, 2004)	$	34.22	$	27.52
Third Quarter (Ended September 30, 2004)	$	31.20	$	21.85
Second Quarter (Ended June 30, 2004)	$	27.59	$	21.50
First Quarter (Ended March 31, 2004)	$	23.94	$	18.45
Fiscal Year Ended December 31, 2003				
Fourth Quarter (from November 20, 2003 through December 31, 2003)	$	18.54	$	16.15

On February 15, 2005, there were 956 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.

Item 6. Selected Financial Data

The consolidated income statement information for the years ended December 31, 2004, 2003 and 2002 and the balance sheet information at December 31, 2004 and 2003 are derived from, and are qualified by reference to, our audited financial statements included elsewhere in this report. The consolidated income statement information for the year ended December 31, 2001 and the balance sheet information at December 31, 2002 and 2001 are derived from audited financial statements that are not included in this report. The consolidated income statement information for the year ended December 31, 2000 and the balance sheet information at December 31, 2000 are derived from our unaudited financial statements that are not included in this report. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; Wyoming and Utah, September 30, 2004; Louisiana and Texas, August 16, 2004; Mississippi, November 3, 2004; and additional Permian Basin interest, December 31, 2004.

	Year Ended December 31,				
	2004	2003	2002	2001	2000
(dollars in millions except per share data)					
Consolidated Income Statement Information:					
Revenues:					
Oil and gas sales	$ 281.1	$ 175.7	$ 122.7	$ 125.2	$ 107.0
Gain (loss) on oil and gas hedging activities	(4.9)	(8.7)	(3.2)	2.3	(3.8)
Gain on sale of oil and gas properties	1.0	—	1.0	11.7	7.7
Gain on sale of marketable securities	4.8	—	—	—	—
Interest income and other	0.1	0.3	—	0.2	0.1
Total revenues	$ 282.1	$ 167.3	$ 120.5	$ 139.4	$ 111.0
Costs and expenses:					
Lease operating	$ 54.2	$ 43.2	$ 32.9	$ 29.8	$ 23.8
Production taxes	16.8	10.7	7.4	6.5	5.4
Depreciation, depletion and amortization	54.0	41.2	43.6	26.9	21.5
Exploration and impairment	6.3	3.2	1.8	0.8	1.1
Phantom equity plan	—	10.9	—	—	—
General and administrative	20.9	12.8	12.0	10.9	6.3
Interest expense	15.9	9.2	10.9	10.2	7.5
Total costs and expenses	$ 168.1	$ 131.2	$ 108.6	$ 85.1	$ 65.6
Income before income taxes and cumulative change in accounting principle	$ 114.0	$ 36.1	$ 11.9	$ 54.3	$ 45.4
Income tax expense	44.0	13.9	4.2	13.1	11.7
Income before cumulative change in accounting principle	70.0	22.2	7.7	41.2	33.7
Cumulative change in accounting principle	—	3.9	—	—	—
Net income	$ 70.0	$ 18.3	$ 7.7	$ 41.2	$ 33.7
Income per common share before cumulative change in accounting principle, basic and diluted	$ 3.38	$ 1.18	$ 0.41	$ 2.20	$ 1.80
Net income per common share, basic and diluted	$ 3.38	$ 0.98	$ 0.41	$ 2.20	$ 1.80
Other Financial Information:					
Net cash provided by operating activities	$ 135.5	$ 96.4	$ 62.6	$ 62.3	$ 42.3
Capital expenditures	$ 532.3	$ 52.0	$ 165.4	$ 99.6	$ 139.1

	As of December 31,				
	2004	2003	2002	2001	2000
(dollars in millions)					
Balance Sheet Information:					
Total assets	$ 1,092.2	$ 536.3	$ 448.5	$ 319.8	$ 256.4
Long-term debt	$ 325.3	$ 188.0	$ 265.5	$ 163.6	$ 139.7
Stockholders' equity	$ 612.4	$ 259.6	$ 122.8	$ 111.5	$ 70.0

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 "should" 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 natural gas prices; our level of success in exploitation, exploration, development and production activities; 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 recently 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 natural gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and natural gas operations; our inability to access oil and natural gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and natural 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 natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and natural gas industry; and risks arising out of our hedging transactions. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

Overview

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Rocky Mountains, Permian Basin, Gulf Coast, Michigan, Mid-Continent and California regions of the United States. Over the last four years, we have emphasized the acquisition of properties that provided current production and significant 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. During periods of radically changing prices, we focus our emphasis on drilling and development of our owned properties. When prices stabilize, we generally direct the majority of our capital to acquisitions.

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

2004 Acquisitions

We completed seven separate acquisitions of producing properties during 2004. The combined purchase price for these seven acquisitions was $535.1 million for total estimated proved reserves as of the effective dates of the acquisitions of approximately 436.1 Bcfe. 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: Equity Oil Company, July 20, 2004; Permian Basin, September 23, 2004; Wyoming and Utah, September 30, 2004; Colorado and Wyoming, August 13, 2004; Louisiana and Texas, August 16, 2004; Mississippi, November 3, 2004; and additional Permian Basin interest, December 31, 2004.

Permian Basin Properties

On September 23, 2004, we 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 our bank credit agreement. Based on the purchase price and estimated proved reserves of 251.1 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.37 per Mcfe of estimated proved reserves.

Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our 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 87.7 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $0.83 per Mcfe of estimated proved reserves.

Other Cash Acquisitions of Properties

Colorado and Wyoming Properties. On August 13, 2004, we acquired interests in four producing oil and gas fields in Colorado and Wyoming. The purchase price was $44.2 million in cash and was funded under our bank credit agreement. Based on the purchase price of $44.2 million and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.11 per Mcfe of estimated proved reserves.

Louisiana and South Texas Properties. On August 16, 2004, we acquired interests in five fields in Louisiana and South Texas. The purchase price was $19.3 million in cash and was funded under our bank credit agreement. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.61 per Mcfe of estimated proved reserves.

Wyoming and Utah Properties. On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah. The purchase price was $35.0 million in cash and was funded under our bank credit agreement. Based on the purchase price of $35.0 million and estimated proved reserves of 30.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.14 per Mcfe of estimated proved reserves.

Mississippi Properties. On November 3, 2004, we acquired an interest in the Lake Como Field in Mississippi. The purchase price was $12.0 million in cash and was funded under our bank credit agreement. Based on the purchase price of $12.0 million and estimated proved reserves of 10.6 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.43 per Mcfe of estimated proved reserves.

Additional Permian Basin Interest. On December 31, 2004, we 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 our bank credit agreement. Based on the purchase price and estimated proved reserves of 4.1 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.72 per Mcfe of estimated proved reserves.

Results of Operations

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

	Years Ended December		
	2004	2003	2002
Net production:			
Natural gas (Bcf)	25.1	21.6	21.4
Oil (MMBbls)	3.7	2.6	2.3
Net sales (in millions):			
Natural gas[(1)]	$ 139.4	$ 104.4	$ 68.6
Oil[(1)]	$ 141.7	$ 71.3	$ 54.1
Average sales prices:			
Natural gas (per Mcf)	$ 5.56	$ 4.78	$ 3.21
Effect of natural gas hedges on average price (per Mcf)	$ —	$ (0.30)	$ (0.01)
Natural gas net of hedging (per Mcf)	$ 5.56	$ 4.48	$ 3.20
Oil (per Bbl)	$ 38.72	$ 27.50	$ 23.35
Effect of oil hedges on average price (per Bbl)	$ (1.33)	$ (0.37)	$ (1.27)
Oil net of hedging (per Bbl)	$ 37.39	$ 27.13	$ 22.08
Costs and expenses (per Mcfe):			
Lease operating expenses	$ 1.15	$ 1.16	$ 0.93
Production taxes	$ 0.36	$ 0.29	$ 0.21
Depreciation, depletion and amortization expense	$ 1.15	$ 1.11	$ 1.24
General and administrative expenses, net of reimbursements	$ 0.45	$ 0.34	$ 0.34

(1) Before consideration of hedging transactions.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased approximately $105.3 million to $281.1 million in 2004. Sales are a function of sales volumes and average sales prices. Our sales volumes increased 26.6% between periods on a Mcfe basis. The volume increase resulted from successful drilling and acquisition activities over the past year that produced new sales volumes that more than offset natural decline. Our average price for natural gas sales increased 16.3% and our average price for crude oil increased 40.8% between periods.

Loss on Oil and Natural Gas Hedging Activities. We hedged 32.3% of our natural gas volumes during 2004 incurring no hedging loss or gain, and 41% of our natural gas volumes during 2003 incurring a hedging loss of $7.7 million. We hedged 50.3% of our oil volumes during 2004 incurring a hedging loss of $4.9 million, and 8.0% of our oil volumes during 2003 incurring a loss of $1.0 million. See Item 7A, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas hedges as of February 15, 2005.

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. At December 31, 2004, we had no investments in marketable securities.

Gain on Sale of Oil and Gas Properties. During the third quarter of 2004, we sold certain undeveloped acreage held by production 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 is equal to the gross proceeds of $1.0 million.

Lease Operating Expenses. Our lease operating expenses per Mcfe decreased from $1.16 during 2003 to $1.15 during 2004. The decrease was less than 1%, which represented improved operating efficiency more than offsetting price inflation caused by increased demand for goods and services in the industry. Our fourth quarter 2004 lease operating expense per Mcfe was also $1.15, indicating that the seven acquisitions we completed during the third and fourth quarters of 2004 have not significantly affected this rate.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in the various taxing jurisdictions. Due to our broad asset base, we expect our production tax rate to vary between 5.8% to 6.2% of oil and natural gas sales revenue. Our production taxes for 2004 and 2003 were 6.0% and 6.1% of oil and natural gas sales, respectively.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased $12.8 million to $54.0 million for 2004. The increase resulted from increased production and an increase in the DD&A rate, as well as the effects of our recent acquisitions. On a Mcfe basis, the rate increased from $1.11 during 2003 to $1.15 in 2004. The increase in rate is primarily due to 2004 property acquisitions, which we purchased at an average cost of $1.23 per Mcfe, which was higher than our historical rate. Changes to the pricing environment can also 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,	
	2004	2003
Depletion	$ 51,424	$ 38,939
Depreciation	832	835
Accretion of asset retirement obligations	1,754	1,482
Total	$ 54,010	$ 41,256

Exploration and Impairment Costs. Our exploration and impairment costs increased $3.1 million to $6.3 million in 2004. The higher exploratory costs were related to our increased purchases of seismic data in 2004 to support our increased drilling budget. The impairment charge represents the write down of cost associated with the High Island Field located off the coast of Texas.

	Year Ended December 31,	
	2004	2003
Exploration	$ 4,177	$ 3,186
Impairment	2,152	—
Total	$ 6,329	$ 3,186

General and Administrative Expenses. We report general and administrative expense net of reimbursements. The components of our general and administrative expense were as follows:

	Year Ended December 31,	
	2004	2003
General and administrative expenses	$ 27,703	$ 18,436
Reimbursements	(6,768)	(5,631)
General and administrative expense, net	$ 20,935	$ 12,805

General and administrative expense before reimbursements increased $9.3 million to $27.7 million during 2004. On a Mcfe basis, the increase between years was from $0.34 to $0.45. The largest component of the increase related to costs associated with our production participation plan. During periods of increased acquisition activity, our general and administrative expense will be higher because we must immediately recognize the discounted value of estimated plan payments to employees 65 and older. The discounted value of estimated payments to employees under 65 is generally amortized over a five year vesting period. Costs related to the production payment plan increased $4.5 million between years to $8.8 million in 2004. The remaining increase was primarily caused by the extra costs of functioning as a public company, increases in the employee base due to our continued growth and general cost inflation. The increase in reimbursements was caused by an increase in operated properties due to the seven property acquisitions. We expect our general and administrative expense to decline to approximately $0.40 per Mcfe sold in 2005 due to cost synergies from recent acquisitions.

Interest Expense. The components of our interest expense were as follows:

	Year Ended December 31,	
	2004	2003
7 ¼% Senior Subordinated Notes due 2012	$ 5,957	$ —
Credit Agreement	5,893	6,643
Alliant Energy Corporation	150	1,224
Accretion of tax sharing liability	2,390	220
Amortization of debt issue costs and debt discount	1,666	1,090
Capitalized interest	(200)	—
Total interest expense	$ 15,856	$ 9,177

The increase in interest expense was primarily due to the May 2004 issuance of $150.0 million of 7 1/4% Senior Subordinated Notes due 2012. In August of 2004, $75.0 million of the face amount of the notes was swapped to a floating rate. The effect of the swap in 2004 was to lower our overall effective interest rate on this debt from 7 1/4% to approximately 6.19%. At December 31, 2004, the floating rate component was set at 4.645% through May 1, 2005, yielding a current weighted average effective interest rate on the $150.0 million issuance of 5.95%.

Interest expense on our credit agreement in 2004 was $750,000 less than 2003. This was primarily the result of average outstanding borrowings in 2004 being approximately $21.0 million lower than 2003. The effective cash interest rate paid in each year on the credit agreement was approximately 3.6%.

The decrease in interest expense related to Alliant Energy Corporation, our former parent company, was due to the March 31, 2003 conversion of $80.9 million of intercompany debt into our equity. The accretion of our tax sharing liability is related to a step-up in tax basis effected immediately prior to our initial public offering in November 2003. The increase was due to a full year of accretion expense in 2004. The increase in debt issue and debt discount amortization was due to the amortization of additional fees in 2004 to refinance our credit agreement and issue $150.0 million of our 7 1/4% Senior Subordinated Notes due 2012.

Income Tax Expense. Income tax expense totaled $44.0 million for 2004 and $13.9 million for 2003, resulting in effective income tax rates of 38.6% for both years. The current portion of income tax expense was $3.9 million in 2004 compared to $2.4 million in 2003. These amounts are 8.8% and 17.1% of the total income tax expense for the respective periods. Prior to our initial public offering in November 2003, we were included in the consolidated federal income tax return of Alliant Energy and calculated our income tax expense on a separate return basis at Alliant Energy's effective income tax rate. Immediately prior to our initial public offering, Alliant Energy effected a step-up in the tax basis of Whiting Oil and Gas Corporation's assets, which had the result of increasing our future tax deductions. These additional deductions, combined with an increase in intangible drilling costs, allowed us to lower the percentage of taxes paid currently, even with the significant increase in oil and gas prices between years.

Cumulative Change in Accounting Principle. Effective January 1, 2003, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." This statement generally applies to legal obligations associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated useful lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and the discount is accreted at the end of each accounting period through charges to DD&A. Upon adoption of SFAS No. 143, we recorded an increase to our discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

Net Income. Net income increased from $18.3 million for 2003 to $70.0 million for 2004. The primary reasons for this increase included 30% higher crude oil and natural gas prices net of hedging between periods, 26.6% increase in equivalent volumes sold, the impact of the cumulative effect of adoption of SFAS No. 143 in 2003, the impact of property and marketable security sales in 2004, offset by higher lease operating expense, general and administrative, DD&A, interest and exploration and impairment costs in 2004.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Oil and Natural Gas Sales. Oil and natural gas sales revenue increased approximately $53.0 million to $175.7 million in 2003. Natural gas sales increased $35.8 million and oil sales increased $17.2 million. The natural gas sales increase was caused by a 49% increase in the average realized natural gas price from $3.21 per Mcf in 2002 to $4.78 per Mcf in 2003 combined with a 230,000 Mcf volume increase in natural gas sales between years. The oil sales increase was caused by a sales volume increase of 275,000 Bbls in 2003 and an 18% increase in the average realized oil price from $23.35 in 2002 to $27.50 in 2003. The volume increase for oil and natural gas primarily resulted from the $217 million of capital expenditures during 2002 and 2003.

Loss on Oil and Natural Gas Hedging Activities. We hedged 41% of our natural gas volumes during 2003, incurring a hedging loss of $7.7 million, and 8% of our natural gas volumes during 2002, incurring a loss of $0.2 million. We hedged 8% of our oil volumes during 2003, incurring a hedging loss of $1.0 million, and 35% of our oil volumes during 2002, incurring a loss of $3.0 million.

Gain on Sale of Oil and Natural Gas Properties. In 2002, we divested one property, realizing a gain of $1.0 million. No significant properties were sold in 2003.

Lease Operating Expenses. Our lease operating expenses per Mcfe increased from $0.93 in 2002 to $1.16 in 2003. The increase resulted from acquisitions during 2002 that caused a larger portion of our operations to be located in Michigan and North Dakota, where weather conditions, sulfur content and remote locations create higher operating costs in comparison to our other areas of operation.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 6.1% in 2003 and 6.0% in 2002. The small increase in the effective rate resulted from additional property purchases in the states of North Dakota and Montana, where effective production tax rates are higher on average than other areas where we own significant producing properties.

Depreciation, Depletion and Amortization. DD&A expense decreased by $2.3 million in 2003. The decrease was a result of a decrease in the average rate from $1.24 per Mcfe in 2002 to $1.11 per Mcfe in 2003, partially offset by increased sales volumes in 2003. The lower rate was a result of higher prices between periods, which allowed for a longer economic production life and corresponding increased reserve volumes and, as a result, a lower DD&A rate.

Exploration Costs. Exploration costs increased $1.4 million to $3.2 million for 2003. The increase was the result of recording three exploratory dry holes during 2003 compared to one exploratory dry hole in 2002.

General and Administrative Expenses. General and administrative expenses increased 6.9%, or $0.8 million, to $12.8 million in 2003. This increase was related to increases in compensation expense associated with increased personnel required to administer our growth and to general cost inflation.

Phantom Equity Plan Compensation. The completion of our initial public offering in November 2003 constituted a "triggering event" under our phantom equity plan. Under this plan, our employees received compensation of $10.9 million in the form of 420,000 shares of our common stock after withholding of shares by us for estimated payroll and income taxes. The phantom equity plan is now terminated.

Interest Expense. Interest expense decreased $1.8 million to $9.2 million in 2003 compared to $10.9 million in 2002. The decrease was due lower average debt levels in 2003 and lower effective interest rates in 2003. The lower debt levels were primarily related to a March 2003 decision by Alliant Energy to convert its remaining $80.9 million of intercompany debt into our equity thereby lowering our future interest expense.

Income Tax Expense. Our effective tax rate was 38.6% in 2003 and 35.3% during 2002. The increased effective tax rate was in part due to our 2002 acquisitions in the state of North Dakota where the effective state income tax rate is higher on average than other areas where we own significant producing properties. In addition, during 2002 we generated $5.4 million of Section 29 credits that we were not able to offset against tax expense. Under our tax separation and indemnification agreement with Alliant Energy, we expect to be compensated for these credits in the future when they are utilized by Alliant Energy. Under generally accepted accounting principles, the recording of the tax credits in 2002 were required to be charged as additional paid-in capital rather than as a decrease to our 2002 income tax expense. Section 29 tax credit provisions of the Internal Revenue Code expired December 31, 2002. Therefore, unless additional legislation is passed, Section 29 credits will not be available in periods subsequent to 2002.

Cumulative Change in Accounting Principle. Effective January 1, 2003, we adopted the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations." This statement generally applies to legal obligations associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated useful lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of AFAS No. 143, we recorded an increase to our discounted abandonment liability of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

Net Income. Net income increased from $7.7 million in 2002 to $18.3 million in 2003. The primary reasons for this increase included higher crude oil and natural gas prices between periods and higher volumes sold, offset by higher lease operating, tax and general and administrative costs due to our growth.

Liquidity and Capital Resources

Overview. We entered 2004 with $53.6 million of cash and cash equivalents. During 2004, we generated $135.5 million from operating activities and $338.4 million from financing activities. We used these sources of cash primarily to finance capital expenditures of $532.3 million used to drill and acquire properties. At December 31, 2004, our debt to total capitalization ratio was 34.9%, we had $1.7 million of cash on hand and $612.4 million of stockholders' equity.

We continually evaluate our capital needs and compare them to our capital resources. Our budgeted capital expenditures for the further development of our property base are $130.0 million to $150.0 million during 2005, an increase from the $79.4 million spent on capitalized development during

2004. Our 2004 development spending was a 96.8% increase from the $40.3 million spent on development during 2003. We also spent $452.7 million on acquisitions in the second half of 2004, funded primarily by borrowings under Whiting Oil and Gas Corporation's credit agreement. Although we have no specific budget for property acquisitions, we will continue to seek property acquisition opportunities that complement our existing core property base. We expect to fund our 2005 development expenditures from internally generated cash flow and cash on hand. We believe that should attractive acquisition opportunities arise or development expenditures exceed $150.0 million, we could finance the additional capital expenditures with cash on hand, operating cash flow, borrowings under our credit agreement, issuances of additional equity or development 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 $750.0 million credit agreement with a syndicate of banks that, as of December 31, 2004, provided a borrowing base of $480.0 million. The borrowing base under the credit agreement is determined in the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders and is subject to regular redetermination on May 1 and November 1 of each year as well as special redeterminations described in the credit agreement. On November 22, 2004, we repaid $240.0 million of debt outstanding under the credit agreement using proceeds from a public offering of 8,625,000 shares of our common stock and cash on hand. As of December 31, 2004, the outstanding principal balance under the credit agreement was $175.0 million.

The credit agreement provides for interest only payments until September 23, 2008, when the entire amount borrowed is due. We may, throughout the 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 our account from time to time in an aggregate amount not to exceed $30.0 million of the amount of the borrowing base available at the time of the request. As of December 31, 2004, letters of credit totaling $0.2 million were outstanding under the credit agreement.

Interest accrues, at our option, at either (1) the base rate plus a margin where the base rate is defined as the higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0% to 0.50% 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. We have consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.250% 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.

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, change material contracts, 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 of greater than 1 to 1. We are in compliance with the credit agreement provision that requires us to hedge at least 60%, but not more than 75%, of our total forecasted PDP production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps, with a minimum floor price of $35 per barrel of oil or $4.50 per MMBtu of natural gas. After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to a maximum of 75% of our forecasted PDP production. In addition, while the credit agreement allows our subsidiaries to make payments to us so that we may pay interest on our senior subordinated notes, it does not allow our subsidiaries to make payments to us to pay principal on the senior subordinated notes. We were in compliance with our covenants under the credit agreement as of December 31, 2004. The credit agreement is secured by a first lien on substantially all of Whiting Oil and Gas Corporation's assets. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement, Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for its guarantee and Equity Oil Company has mortgaged substantially all of its assets as security for its guarantee.

7 1/4% Senior Subordinated Notes due 2012. In May 2004, we issued, in a private placement, $150.0 million aggregate principal amount of our 7 1/4% senior subordinated notes due 2012. The net proceeds of the offering were used to retire all of our debt outstanding under Whiting Oil and Gas Corporation's credit agreement. 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. The indenture governing the notes contains 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 us and our restricted subsidiaries taken as a whole and enter into hedging contracts. These covenants may limit the discretion of our management in operating our business. We were in compliance with these covenants as of December 31, 2004. 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.

Alliant Energy Promissory Note. In conjunction with our initial public offering in November 2003, we issued a promissory note payable to Alliant Energy Corporation, our former parent company, in the aggregate principal amount of $3.0 million. The note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due on November 25, 2005.

Tax Separation and Indemnification Agreement with Alliant Energy. In connection with our initial public offering in November 2003, we entered into a tax separation and indemnification agreement with Alliant Energy. Pursuant to this agreement, we and Alliant Energy made a tax election with the effect that the tax basis 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 basis of our assets. This additional basis is 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 to 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 basis 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. The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders' equity. During 2004, we did not make any payments under this agreement but did recognize $2.4 million of accretion expense, which is included as a component of interest expense. Our estimate of payments to be made under this agreement of $4.2 million in 2005 is reflected as a current liability at December 31, 2004.

Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of December 31, 2004 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include asset retirement obligations or production participation plan liabilities since we cannot determine with accuracy the timing of future payments. This table also does not include interest expense since we cannot determine with accuracy the timing of future loan advances and repayments and the future interest rate to be charged under floating rate instruments. During August 2004, we entered into an interest rate swap on $75.0 million of our $150.0 million fixed rate 7 1/4% senior subordinated notes due 2012. The amount of interest we expect to pay relating to the $75.0 million of our senior subordinated notes remaining under the 7 1/4% fixed rate is $5.4 million annually through the term of the notes.

	Payments Due by Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Long-Term Debt	$ 328,428	$ 3,167	$ —	$ 175,000	$ 150,261
Operating Lease	6,417	1,100	2,200	2,200	917
Tax Separation and Indemnification Agreement with Alliant Energy[1]	31,180	4,214	8,273	6,961	11,732
Total	$ 366,025	$ 8,481	$ 10,473	$ 184,161	$ 162,910

[1] Amounts shown are estimates based on estimated future income tax benefits from the increase in tax basis described under "Tax Separation and Indemnification Agreement with Alliant Energy" above.

Off-Balance Sheet Arrangements. 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, 2005 increased to 50% of the actual price received in excess of $20.16 per barrel. As of December 31, 2004, approximately 46,000 net barrels of crude oil per month (8.7% of December 2004 estimated 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 2004, 2003 and 2002, we paid $4.8 million, $2.3 million and $0.8 million, respectively, under this agreement. As of December 31, 2004, we have accrued an additional $549,000 as currently payable.

New Accounting Policies

In December 2004, the FASB issued a revision of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS 123R). SFAS 123R supersedes Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and its related implementation guidance. SFAS 123R establishes standards for the accounting for transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS 123R does not change the accounting guidance for share-based payment transactions with parties other than employees provided in SFAS 123 as originally issued and EITF Issue No. 96-18, "Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services." SFAS 123R is effective for interim reporting period that begins after June 15, 2005. The adoption of SFAS 123R is not expected to have a material impact on our consolidated financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operation is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. 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 financial position and results of operations and which require the application of significant judgment by our management.

Revenue Recognition. We predominantly derive our revenue from the sale of produced crude oil and natural 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.

Hedging. Our crude oil and natural gas hedges are designed to be treated as cash flow hedges under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activity." This policy is significant since it impacts the timing of revenue recognition. Under this pronouncement, the majority of our hedging gains or losses are recorded in the month the contracts settle. We reflect this as an adjustment to revenue through the "Loss on oil and gas hedging activities" line item in our consolidated income statements. If our hedges did not qualify for cash flow hedge treatment, then our consolidated income statements could include large non-cash fluctuations in this line item, particularly in volatile pricing environments, as our contracts are marked to their period end market values.

Successful Efforts Accounting. We account for our oil and natural gas operations using the successful efforts method of accounting. Under this method, all costs associated with property acquisition, 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 natural gas production costs. Except for one small property in Canada, all of our properties are located within the continental United States and the Gulf of Mexico.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties, and our long-term production participation plan liability. Proved oil and natural 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 approximately 96.5% of the pre-tax PV10% value of our proved reserves as of January 1, 2005 and our engineering staff evaluated the remainder. 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 natural 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 and impairment calculations in the same period that changes to the reserve estimates are made.

Impairment of Oil and Natural Gas Properties. We review the value of our oil and natural gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. We provide for impairments on undeveloped property when we determine that the property will not be developed or a permanent impairment in value has occurred. Impairments of proved producing properties are calculated by comparing future net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded book cost 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.

Production Participation Plan. We have a Production Participation Plan for all employees. On an annual basis, interests in oil and gas properties acquired or developed during the year are allocated to the plan on a discretionary basis. Once allocated, the interests (not legally conveyed) are fixed. The short-term obligation related to the Production Participation Plan is included in the "Accrued Employee Benefits" line item on our consolidated balance sheet. 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 above under "Revenue Recognition". The long-term obligation related to the Production Participation Plan is the "Production Participation Plan Liability" line item on the consolidated balance sheet. This liability is derived primarily from discounted reserve report estimates, which as discussed above, are subject to revision as more information becomes available. 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.

Income Taxes. We provide for income taxes in accordance with Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes." Deferred income taxes are provided for the difference between the tax basis of assets and liabilities and the carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is settled. Since our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to actual in the period we file our tax returns.

Effects of Inflation and Pricing

We experienced increased costs during 2004, 2003 and 2002 due to increased demand for oil field products and services. The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Material changes in prices impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural 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 natural gas could result in increases in the cost of material, services and personnel.

Acquisition of Green River Basin Properties

On February 23, 2005, we announced that we had entered into a purchase and sale agreement to acquire operated interests in five producing gas fields in the Green River Basin of Wyoming. The purchase price will be $65.0 million, or $1.29 per Mcfe, for estimated proved reserves of 50.5 Bcfe. We will operate approximately 95% of the net daily production from the properties which is currently 6.3 MMcfe/d. The purchase and sale agreement is subject to standard conditions to closing, including our completion of title and environmental due diligence, with closing expected by the end of March 2005. The acquisition will be funded under our credit agreement.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile, 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 2004 production, our income before income taxes for 2004 would have moved up or down approximately $2.4 million for every $0.10 change in natural gas prices and approximately $3.4 million for each $1.00 change in crude oil prices.

We periodically enter into derivative contracts to manage our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been with no-cost collars, although we evaluate other forms of derivative instruments as well. Our derivative contracts have historically qualified for cash flow hedge accounting under SFAS No. 133. This accounting treatment allows the aggregate change in fair market value to be recorded as other comprehensive income on the consolidated balance sheet. Recognition in the consolidated income statement occurs in the period of contract settlement. We have met the requirement under our credit agreement to hedge at least 60%, but not more than 75%, of our total forecasted PDP production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps with a minimum floor price of $35 per barrel of oil or $4.50 per MMBtu. After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to a maximum of 75% of our forecasted PDP production. We also seek to diversify our hedge position with various counterparties where we have clear indications of their current financial strength.

Our outstanding hedges as of February 15, 2005 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)		NYMEX Floor/Ceiling
Natural Gas	01/2005 to 03/2005	400,000	$	5.00/12.75
Natural Gas	01/2005 to 03/2005	500,000	$	5.00/11.00
Natural Gas	01/2005 to 03/2005	600,000	$	5.00/10.50
Natural Gas	04/2005 to 06/2005	1,500,000	$	4.50/8.25
Natural Gas	07/2005 to 09/2005	1,500,000	$	4.50/8.60
Natural Gas	10/2005 to 12/2005	1,500,000	$	4.50/10.00
Natural Gas	01/2006 to 03/2006	750,000	$	5.90/10.30
Crude Oil	01/2005 to 03/2005	50,000	$	35.00/50.75
Crude Oil	01/2005 to 03/2005	94,000	$	35.00/49.60
Crude Oil	01/2005 to 03/2005	120,000	$	37.00/46.90
Crude Oil	01/2005 to 03/2005	80,000	$	37.00/50.60
Crude Oil	04/2005 to 06/2005	250,000	$	37.00/46.65
Crude Oil	07/2005 to 09/2005	250,000	$	35.00/47.25
Crude Oil	10/2005 to 12/2005	125,000	$	35.00/60.55
Crude Oil	10/2005 to 12/2005	125,000	$	35.00/65.75
Crude Oil	01/2006 to 03/2006	250,000	$	40.00/51.50

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 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 of $600,000 for 2005. For the 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 of $1.1 million for 2005.

We have also entered into 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 February 15, 2005 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)		2005 Price Per MMBtu
Natural Gas	01/2002 to 12/2011	51,000	$	4.39
Natural Gas	01/2002 to 12/2012	60,000	$	3.89

The table below summarizes the hedges and fixed price marketing contracts described above:

Hedges and Contracts Summary	Hedged and Contracted (MMBtu)/(Bbl) per Month	As a Percentage of December 2004 Production (Gas/Oil)
January – March 2005	1,611,000/344,000	60%/65%
April – June 2005	1,611,000/250,000	60%/47%
July – September 2005	1,611,000/250,000	60%/47%
October – December 2005	1,611,000/250,000	60%/47%
January – March 2006	861,000/250,000	32%/47%

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, 2004, our outstanding principal balance under our credit agreement was $175.0 million and the interest rate on the entire outstanding principal balance was fixed at 3.42% through January 30, 2005. We subsequently fixed the interest rate on the entire outstanding principal balance at 3.73% through April 29, 2005. At December 31, 2004, the carrying amount approximated fair market value. Assuming a constant debt level of $175.0 million, the cash flow impact for 2005 resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $1.2 million.

Interest Rate Swap

In August 2004, we entered into an interest rate swap contract to hedge the fair value of $75.0 million of our 7 1/4% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness under the provisions of Statement of Financial Accounting Standards No. 133, 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. As of December 31, 2004, we have recorded a long term derivative asset of $1.3 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding debt increase.

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, 2004 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, 2004, 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.

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, 2004, 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, 2004, 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, 2004, 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 and financial statement schedule as of and for the year ended December 31, 2004 of the Company and our report dated February 24, 2005 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 24, 2005

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, 2004 and 2003, 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, 2004. Our audits also included the financial statement schedule listed in Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements referred to above present fairly, in all material respects, the financial position of Whiting Petroleum Corporation and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations to conform to Statement of Financial Accounting Standards No. 143.

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, 2004, 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 24, 2005 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 24, 2005

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF DECEMBER 31, 2004 AND 2003

In thousands, except per share data

	2004	2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,660	$ 53,585
Accounts receivable trade, net	63,489	24,020
Deferred income taxes	2,368	—
Prepaid expenses and other	10,566	2,666
Total current assets	78,083	80,271
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	1,225,676	615,764
Unproved properties	6,038	1,637
Other property and equipment	4,554	2,684
Total property and equipment	1,236,268	620,085
Less accumulated depreciation, depletion and amortization	(244,246)	(192,794)
Total property and equipment—net	992,022	427,291
OTHER LONG-TERM ASSETS	22,101	9,988
DEFERRED INCOME TAXES	—	18,735
TOTAL	$ 1,092,206	$ 536,285

(Continued)

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2004 AND 2003

In thousands, except per share data

	2004	2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 21,865	$ 15,918
Oil and gas sales payable	4,987	2,406
Accrued employee benefits	7,808	5,275
Production taxes payable	8,254	2,574
Current portion of tax sharing liability	4,214	—
Current portion of long-term debt	3,167	—
Derivative liability	1,670	2,145
Income taxes payable and other liabilities	129	693
Total current liabilities	52,094	29,011
ASSET RETIREMENT OBLIGATIONS	31,639	23,021
PRODUCTION PARTICIPATION PLAN LIABILITY	9,579	7,868
TAX SHARING LIABILITY	26,966	28,790
LONG-TERM DEBT	325,261	188,017
DEFERRED INCOME TAXES	34,281	—
COMMITMENTS AND CONTINGENCIES (Note 7)		
STOCKHOLDERS' EQUITY:		
Common stock, $.001 par value; 75,000,000 shares authorized, 29,717,808 and 18,750,000 shares issued and outstanding as of December 31, 2004 and 2003, respectively	30	19
Additional paid-in capital	455,635	170,367
Accumulated other comprehensive loss	(1,025)	(223)
Deferred compensation	(1,715)	
Retained earnings	159,461	89,415
Total stockholders' equity	612,386	259,578
TOTAL	$ 1,092,206	$ 536,285

See notes to consolidated financial statements. (Concluded)

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

In thousands, except per share data

	2004	2003	2002
REVENUES:			
Oil and gas sales	$ 281,057	$ 175,731	$ 122,709
Loss on oil and gas hedging activities	(4,875)	(8,680)	(3,184)
Gain on sale of marketable securities	4,835	—	—
Gain on sale of oil and gas properties	1,000	—	978
Interest income and other	123	330	9
Total	282,140	167,381	120,512
COSTS AND EXPENSES:			
Lease operating	54,212	43,213	32,867
Production taxes	16,793	10,691	7,363
Depreciation, depletion and amortization	54,010	41,256	43,601
Exploration and impairment	6,329	3,186	1,811
General and administrative	20,935	12,805	11,980
Phantom equity plan	—	10,914	—
Interest expense	15,856	9,177	10,938
Total costs and expenses	168,135	131,242	108,560
INCOME BEFORE INCOME TAXES AND CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	114,005	36,139	11,952
INCOME TAX EXPENSE (BENEFIT):			
Current	3,882	2,389	(6,408)
Deferred	40,077	11,560	10,631
Total income tax expense	43,959	13,949	4,223
INCOME BEFORE CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	70,046	22,190	7,729
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE, NET OF TAX	—	(3,905)	—
NET INCOME	$ 70,046	$ 18,285	$ 7,729
Income per share before cumulative change in accounting principle, basic and diluted	$ 3.38	$ 1.18	$ 0.41
Cumulative change in accounting principle	—	(0.20)	—
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 3.38	$ 0.98	$ 0.41
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	20,735	18,750	18,750
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	20,768	18,750	18,750

See notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME FOR THE YEARS ENDED DECEMBER 31, 2004, 2003, AND 2002

In thousands, except per share data

	Common Stock		Additional Paid-in	Accumulated Other Comprehensive	Deferred	Retained	Total Stockholders'	Comprehensive
	Shares	**Amount**	**Capital**	**Income (Loss)**	**Compensation**	**Earnings**	**Equity**	**Income**
BALANCES—January 1, 2002	18,750	$ 19	$ 47,856	$ 190	$ —	$ 63,401	$111,466	$ 41,418
Net income	—	—	—	—	—	7,729	7,729	7,729
Unrealized net gain on marketable equity securities for sale	—	—	—	240	—	—	240	240
Tax contribution from Alliant	—	—	5,363	—	—	—	5,363	—
Change in derivative instrument fair value	—	—	—	(1,980)	—	—	(1,980)	(1,980)
BALANCES—December 31, 2002	18,750	19	53,219	(1,550)	—	71,130	122,818	5,989
Net income	—	—	—	—	—	18,285	18,285	18,285
Unrealized net gain on marketable equity securities for sale	—	—	—	664	—	—	664	664
Change in derivative instrument fair value	—	—	—	663	—	—	663	663
Conversion of Alliant note payable to equity	—	—	80,931	—	—	—	80,931	—
Issuance of note payable	—	—	(3,000)	—	—	—	(3,000)	—
Phantom equity plan contribution	—	—	10,666	—	—	—	10,666	—
Tax basis step-up	—	—	28,551	—	—	—	28,551	—
BALANCES—December 31, 2003	18,750	19	170,367	(223)	—	89,415	259,578	19,612
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 instrument fair value	—	—	—	292	—	—	292	292
Issuance of stock – Equity Oil Company merger	2,237	2	43,296	—		—	43,298	
Issuance of stock – secondary offering	8,625	9	239,677	—	—	—	239,686	—
Deferred compensation stock issued	106	—	2,295	—	(2,295)	—	—	—
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

See notes to consolidated financial statements.

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

In thousands

	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 70,046	$ 18,285	$ 7,729
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	54,010	41,256	43,601
Deferred income taxes	40,077	11,560	10,631
Amortization of debt issuance costs and debt discount	1,466	1,091	71
Accretion of tax sharing agreement	2,390	220	—
Amortization of deferred compensation	580	—	—
Gain on sale of marketable securities	(4,835)	—	—
Gain on sale of oil and gas properties	(1,000)	—	(978)
Impairment of oil and gas properties	2,152	—	—
Phantom equity plan	—	6,510	—
Cumulative change in accounting principle	—	3,905	—
Changes in assets and liabilities:			
Accounts receivable	(34,633)	(307)	(1,129)
Income taxes and other receivable	—	3,814	1,538
Other assets	(10,771)	295	(1,229)
Asset retirement obligations	(416)	(147)	(48)
Production participation plan liability	4,390	651	1,685
Other current liabilities	12,091	9,229	710
Net cash provided by operating activities	135,547	96,362	62,581
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash acquisition capital expenditures	(452,662)	(7,219)	(142,307)
Drilling capital expenditures	(79,376)	(40,336)	(23,136)
Proceeds from sale of marketable securities	5,420	—	—
Proceeds from sale of oil and gas properties	1,000	—	1,534
Equity Oil Company cash paid in excess of cash received	(256)	—	—
Acquisition of partnership interests, net of cash received	—	(4,453)	—
Restricted cash	—	—	6,434
Net cash used in investing activities	(525,874)	(52,008)	(157,475)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Advances (repayments) from Alliant, net	—	4,616	(83,119)
Issuance of common stock	239,686	—	—
Issuance of 7¼% Senior Subordinated Notes due 2012	148,890	—	—
Issuance of long-term debt under credit agreement	445,800	—	185,000
Payments on long-term debt under credit agreement	(484,800)	—	—
Debt issuance costs	(11,174)	(218)	(3,171)
Net cash provided by financing activities	338,402	4,398	98,710
NET CHANGE IN CASH AND CASH EQUIVALENTS	(51,925)	48,752	3,816
CASH AND CASH EQUIVALENTS:			
Beginning of period	53,585	4,833	1,017
End of period	$ 1,660	$ 53,585	$ 4,833
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid (refunded) for income taxes	$ 4,479	$ (1,425)	$ (7,946)
Cash paid for interest	$ 11,222	$ 6,464	$ 10,866
NONCASH FINANCING ACTIVITIES:			
Assumption of debt – Equity Oil Company merger	$ 29,000	$ —	$ —
Issuance of common stock – Equity Oil Company merger	$ 43,298	$ —	$ —
Alliant debt converted to equity	$ —	$ 80,931	$ —

See notes to consolidated financial statements.

In thousands, except per share data

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Whiting Petroleum Corporation ("Whiting" or the "Company") is a Delaware corporation that prior to its initial public offering in November 2003 was a wholly owned indirect subsidiary of Alliant Energy Corporation ("Alliant Energy" or "Alliant"), a holding company whose primary businesses are utility companies. Just prior to the public offering of our common stock by Alliant Energy, the Company in effect split its common stock, issuing 18,330 shares for the 1 previously held by Alliant Energy. All periods presented have been adjusted to reflect the current capital structure. Alliant Energy historically provided the Company with cash management and other services. Whiting acquires, develops and explores for producing oil and gas properties primarily in the Rocky Mountains, Permian Basin, Gulf Coast, Michigan, Mid-Continent and California 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 is the sole general partner. All significant intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates—The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make significant estimates. These estimates are an integral part of the financial statements and actual results could differ from those estimates. Certain estimates associated with the carrying amount of oil and gas properties are particularly sensitive to changes in pricing, production rates and cost. A decline in the price of oil or gas or rate of production or increase in costs associated with the operations of oil and gas properties could adversely impact the economic value of the oil and gas properties.

Cash and Cash Equivalents—Cash equivalents consist of money market accounts and investments which have an original maturity of three months or less.

Fair Value of Financial Instruments—The Company's financial instruments, including cash and cash equivalents, restricted cash, accounts receivable and payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The short-term debt has a recorded value that approximates its fair value since its fixed interest rate approximates market. 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 is recorded at fair value as discussed in Note 5. The Company's 7 ¼% Senior Subordinated Notes due 2012 are recorded at cost and the fair value is disclosed in Note 5. The Company's derivative instruments and investment in available for sale securities are marked-to-market with changes in value being recorded in accumulated other comprehensive income.

Concentration of Credit Risk—Substantially all of the Company's receivables are within the oil and gas industry, primarily from the sale of oil and gas products and billings to working interest owners. Although diversified within many companies, collectibility is dependent upon the general economic conditions of the industry. Most of the receivables are not collateralized and to date, the Company has had minimal bad debts.

Further, our natural gas futures and swap contracts also expose us to credit risk in the event of nonperformance by counterparties. Generally, these contracts are with major investment grade financial institutions and historically the Company has not experienced material credit losses. The Company believes that its credit risk related to the natural gas futures and swap contracts is no greater than the risk associated with primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers the Company's overall business risk; but, as a result of Whiting's hedging activities the Company may be exposed to greater credit risk in the future. No single purchaser of oil and gas accounted for 10% or more of total sales for the years ended December 31, 2004, 2003 or 2002.

At December 31, 2004 and 2003, the Company had recorded an allowance for doubtful accounts of $250 and $300, respectively.

Oil and Gas Producing Activities—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 costs of exploratory and development wells are capitalized when incurred, 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. The costs of development wells are capitalized whether productive or nonproductive.

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 2004, 2003 and 2002, the Company capitalized interest expense of $200, $0 and $0, respectively.

Geological and geophysical costs of exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment is recorded for unproved properties if the capitalized costs are not considered to be realizable. Depletion, depreciation and amortization ("DD&A") of capitalized costs of proved oil and gas properties is provided on a field-by-field basis using the units of production method based upon proved reserves. The computation of DD&A takes into consideration the anticipated proceeds from equipment salvage and the Company's expected cost to abandon its well interests.

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 future net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded book cost at the end of each period. If the net capitalized cost exceeds net future cash flows, then 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. During 2004 the Company recorded a $2.2 million impairment charge related to proved properties. During 2003 and 2002, the Company did not record any impairment charges related to proved properties.

Gains and losses are recognized on sales of entire interests in proved and unproved properties. Sales of partial interests are generally treated as recoveries of costs.

Other Property and Equipment—Other property and equipment are stated at cost and depreciated using the straight-line method over a period of four years. Maintenance and repair costs which do not extend the useful lives of the property and equipment are charged to expense as incurred. When other property and equipment is sold or retired, the related costs and accumulated depreciation are removed from the accounts.

As of December 31, 2004 and 2003, the balance of other property and equipment was $4,554 and $2,684, respectively. Depreciation expense was approximately $832, $836 and $770 for the years ended December 31, 2004, 2003 and 2002, respectively.

Bank Fees—Bank fees are being amortized to interest expense using the interest method over the life of the loan.

Reimbursed Overhead—The Company provides various administrative services to its partnerships and owners of certain oil and gas properties for which the Company receives overhead reimbursements. Amounts earned are included as a reduction to general and administrative expense and totaled $6,768, $5,631 and $5,505 for the years ended December 31, 2004, 2003 and 2002, respectively.

Abandonment Liability—Effective January 1, 2003, the Company adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This Statement generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize the fair value of asset retirement obligations in the financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to the Company, this Statement applies directly to the plug and abandonment liabilities associated with the Company's net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to depreciation, depletion and amortization expense. If the obligation is settled for other than the carrying amount, then a gain or loss is recognized on settlement.

Revenue Recognition—The Company uses the sales method to record oil revenues whereby revenue is recognized based on the amount of oil sold to purchasers. The Company uses the entitlements method to record natural gas revenues whereby revenue is recognized for the Company's share of natural gas produced, regardless of whether the Company has taken its share of the related revenue. Gas imbalance receivables (payables) are valued at the lower (higher) of current market value or the price in effect at the time of production. As of December 31, 2004 and 2003, the Company was in an under produced imbalance position of approximately 339,000 Mcf and 206,000 Mcf, respectively.

Derivative Instruments—Whiting is exposed to market risk in the pricing of its oil and gas production. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, transportation availability and price, and general economic conditions. Worldwide political developments have historically also had an impact on oil and gas prices. Periodically, Whiting utilizes oil and gas swaps and forward contracts to mitigate the impact of oil and gas price fluctuations related to its sales of oil and gas. During the years 2004, 2003 and 2002, Whiting entered into a number of oil and gas swaps and forward contracts.

At December 31, 2004, the Company had 14 derivative contracts outstanding with a fair market value unrealized loss of $1,670 of which $1,025 was recorded as a component of accumulated other comprehensive loss and $645 was recorded as an decrease to the deferred tax liability.

At December 31, 2003, the Company had five derivative contracts outstanding with a fair market value unrealized loss of $2,145 of which $1,317 was recorded as a component of accumulated other comprehensive loss and $828 was recorded as an increase to the deferred tax asset.

For the years ended December 31, 2004, 2003, and 2002, Whiting recognized losses of approximately $4.9 million, $8.7 million and $3.2 million from the settlement of derivative instruments, respectively.

The Company has also entered into an interest rate swap derivative instrument as further explained in Note 5.

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 other comprehensive income.

As of December 31, 2003, the Company had 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 $585 and a fair value of approximately $2,367. During 2004, the Company sold all of its holdings for $5,420, realizing a gain on sale of $4,835. As of December 31, 2003, the Company recorded an unrealized holding gain of $1,782, correspondingly $1,094 was recorded as a component of accumulated other comprehensive income and $688 was recorded as a decrease to the deferred tax asset.

Income Taxes—Prior to the Company's initial public offering in November 2003, the Company was included in the consolidated federal income tax return of Alliant Energy but was treated as a separate entity for income tax purposes. The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. These differences will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively.

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. The dilutive effect of these securities was immaterial to the calculation.

Industry Segment and Geographic Information—The Company operates in one industry segment, which is the exploration, development and production of natural gas and crude oil, and substantially all of the Company's operations are conducted in the United States. Consequently, the Company currently reports as a single industry segment.

New Accounting Pronouncements—In December 2004, the FASB issued a revision of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (SFAS 123R). SFAS 123R supersedes Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and its related implementation guidance. SFAS 123R establishes standards for the accounting for transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS 123R does not change the accounting guidance for share-based payment transactions with parties other than employees provided in SFAS 123 as originally issued and EITF Issue No. 96-18, "Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services." SFAS 123R is effective for interim reporting period that begins after June 15, 2005. The adoption of this Statement is not expected to have a material impact on the consolidated financial statements.

2. *ASSET RETIREMENT OBLIGATIONS*

Effective January 1, 2003, the Company adopted the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize the fair value of asset retirement obligations in its financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to the Company, this statement applies directly to the plug and abandonment liabilities associated with its net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, the Company recorded an increase to its discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million). The Company had an additional $4.2 million asset retirement obligation accrued at January 1, 2003 relating to its retained obligation with respect to the Point Arguello facility located offshore from California.

The Company's estimated liability for plugging and abandoning its oil and gas wells and certain obligations for previously owned onshore and offshore facilities in California is discounted using a credit-adjusted risk-free rate of approximately 7%. Upon adoption of SFAS No. 143, the Company recorded an increase to its discounted abandonment liability of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

The following table provides a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2004 and 2003.

	Year Ended December 31,	
	2004	**2003**
Beginning asset retirement obligation	$ 23,021	$ 4,232
SFAS 143 adoption	—	16,458
Additional liability incurred	7,280	996
Accretion expense	1,754	1,482
Liabilities settled	(416)	(147)
Ending asset retirement obligation	$ 31,639	$ 23,021

No revisions have been made to the timing or the amount of the original estimate of undiscounted cash flows during 2004 or 2003.

3. *INVESTMENT IN PARTNERSHIPS*

At December 31, 2004, the Company was the general partner in three private oil and gas income and development limited partnerships. The partnership agreements generally provide for a capital contribution by the Company of 8% to 10% of total capital for a 13% to 17% interest in the net revenue of the partnerships. As a general partner in these partnerships, Whiting may be liable to the extent any such partnerships incur liabilities in excess of the value of its assets. In 2003, the Company purchased the limited partnership interests in three limited partnerships in which the Company was general partner for $4,453. Additionally, Whiting is a limited partner in a partnership that owns a pipeline that transports carbon dioxide.

4. *RELATED PARTY TRANSACTIONS*

In conjunction with the Company's initial public offering in November 2003, the Company issued a promissory note payable to Alliant Energy in the aggregate principal amount of $3.0 million. The note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due on November 25, 2005 (see Note 5).

Alliant Energy had loaned the Company an aggregate $80.5 million as of December 31, 2002. The note bore interest at a floating rate which ranged from 6.9% to 4.4% during 2003 and 2002, respectively. On March 31, 2003, Alliant Energy converted its outstanding intercompany balance of $80,931 to equity of the Company. The Company incurred approximately $1.2 million and $10.5 million in interest expense related to this note during the years ended December 31, 2003 and 2002, respectively.

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.

The Company provides general and administrative services to its partnerships for which the partnerships are billed monthly. Amounts so charged are based on flat rates provided for in each respective Partnership Agreement. The Company pays operating expenses for its partnerships for which it receives reimbursement. The Company may also advance funds to its partnerships for property development. The amounts due to affiliates at December 31, 2004 and 2003 was $324 and $124, respectively and represent cash receipts from the sale of oil and gas to be distributed to the partnerships offset by the net amount of advances to the partnerships for property development.

5. *LONG-TERM DEBT*

Long-term debt consisted of the following at December 31, 2004 and 2003:

	2004	**2003**
Credit agreement	$ 175,000	$ 185,000
7 ¼% Senior Subordinated Notes due 2012	150,261	—
Alliant Energy—see Note 4	3,167	3,017
Total	328,428	188,017
Current portion of long-term debt	(3,167)	—
Long-term debt	$ 325,261	$ 188,017

Credit Agreement—Whiting Oil and Gas Corporation has a $750.0 million credit agreement with a syndicate of banks that, as of December 31, 2004, provided a borrowing base of $480.0 million. The borrowing base under the credit agreement is determined in 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 redetermination on May 1 and November 1 of each year as well as special redeterminations described in the credit agreement. On November 22, 2004, the Company repaid $240.0 million of debt outstanding under the credit agreement using proceeds from a public offering of 8,625,000 shares of the Company's common stock and cash on hand. As of December 31, 2004, the outstanding principal balance under the credit agreement was $175 million.

The credit agreement provides for interest only payments until September 23, 2008, when the entire amount borrowed is due. Whiting Oil and Gas Corporation may, throughout the 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 Corporation or other designated subsidiaries of the Company from time to time in an aggregate amount not to exceed $30.0 million of the amount of the borrowing base available at the time of the request. As of December 31, 2004, letters of credit totaling $0.2 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 federal funds rate plus 0.5% or the prime rate and the margin varies from 0% to 0.50% 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 0.250% 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, 2004, the interest rate on the entire outstanding principal balance of $175.0 million was fixed at 3.42% through January 30, 2005. On January 30, 2005, the Company fixed the interest rate on the entire outstanding principal balance at 3.73% through April 29, 2005.

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 contracts, 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 of greater than 1 to 1. The Company is in compliance with the credit agreement provision that requires the Company to hedge at least 60% but not more than 75% of its total forecasted proved developed producing production for the period through December 31, 2005 in the form of costless collars, with a minimum floor price of $35 per barrel of oil or $4.50 per million British Thermal Units (MMBtu). After December 31, 2005, the credit agreement will not require the Company to hedge any of its production, but will continue to limit the Company's hedging to a maximum of 75% of forecasted proved developed producing production. In addition, while the credit agreement allows the Company's subsidiaries to make payments to the Company so that it may pay interest on its senior subordinated notes, it does not allow the Company's subsidiaries to make payments to it to pay principal on the senior subordinated notes. The Company was in compliance with its covenants under the credit agreement as of December 31, 2004. The credit agreement is secured by a first lien on substantially all of Whiting Oil and Gas Corporation's assets. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement, Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for its guarantee and Equity Oil Company has mortgaged substantially all of its assets as security for its guarantee.

7 ¼% Senior Subordinated Notes due 2012—In May 2004, the Company issued, in a private placement, $150.0 million aggregate principal amount of its 7 1/4% senior subordinated notes due 2012. The net proceeds of the offering were used to refinance debt outstanding under the Company's credit agreement. 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 the Company and are subordinated to all of the Company's senior debt. The indenture governing the notes contains various restrictive covenants that 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 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 limit the discretion of the Company's management in operating the Company's business. In addition, Whiting Oil and Gas Corporation's credit agreement restricts the ability of the Company's subsidiaries to make payments to the Company. The Company was in compliance with these covenants as of December 31, 2004. Three of the Company's subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company (the "Guarantors"), have fully, unconditionally, jointly and severally guaranteed the Company's obligations under the notes. All of the Company's subsidiaries other than the Guarantors are minor within the meaning of Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission, and the Company has no independent assets or operations. Based on the market price of the 7 1/4% senior subordinated notes due 2012, their estimated fair value was $157.1 million as of December 31, 2004.

Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of $75 million of its 7 1/4% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness under the provisions of Statement of Financial Accounting Standards No. 133, 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. The six-month LIBOR rate in effect at December 31, 2004 was 2.3%. 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 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 million for the six month period. As of December 31, 2004, the Company has recorded a long term derivative asset of $1.3 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding debt increase to the 7 1/4% Senior Subordinated Notes due 2012.

Short-Term Debt—In conjunction with the Company's initial public offering in November 2003, the Company issued a promissory note payable to Alliant Energy in the aggregate principal amount of $3.0 million. The promissory note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due on November 25, 2005.

6. *EMPLOYEE BENEFIT PLANS*

Production Participation Plan—The Company has a Production Participation Plan for all employees. On an annual basis, interests in oil and gas properties acquired or developed during the year are allocated to the plan on a discretionary basis. Once allocated, the interests (not legally conveyed) are fixed. Allocations prior to 1995 consisted of 2% - 3% overriding royalty interests. Allocations since 1995 have been 2% - 5% net revenue interests. Prior to plan year 2004, plan participants generally vested ratably over their initial five years of employment in all income allocated to the plan on their behalf and forfeitures were re-allocated among other Plan participants. The Production Participation Plan was modified in 2004 to provide that (1) for years 2004 and beyond, employees will vest at a rate of 20% per year with respect to 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) for years 2004 and beyond, if there are forfeitures, the interests will inure to the benefit of the Company.

Payments to participants of the plan are made annually in cash after year end and amounted to $7.1 million, $4.4 million and $3.6 million for 2004, 2003 and 2002, respectively. The Company has estimated the total discounted vested obligations, including the amounts above, at December 31, 2004 and 2003 as being $16.7 million and $12.3 million, respectively. Plan expense for 2004, 2003 and 2002 was approximately $8.8 million, $4.3 million and $5.3 million, respectively.

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. This plan prohibits the repricing of outstanding stock options without stockholder approval. During 2004, the Company granted 112,921 shares of restricted stock under this plan and 7,724 shares were forfeited. The shares of restricted stock were recorded at fair value of $2.3 million, net of forfeitures, and are being amortized to general and administrative expense over their three-year vesting period.

Phantom Equity Plan—The Company also had a phantom equity plan as an incentive to employees. The phantom equity plan award was calculated based on the growth of the Company's proved oil and gas reserves before income taxes from January 1, 2000 to a triggering event, less increases in debt for the same period (the "Value Appreciation"). The Value Appreciation was then multiplied by a sharing percentage of 5%. The completion of the initial public offering in November 2003 constituted a triggering event under the plan and, consequently, the Company's employees received a $10.9 million award in the form of approximately 420,000 shares of Whiting common stock after withholding of shares for payroll and income taxes. Alliant Energy was required to fund the majority of plan expense by contributing cash and stock to the Company in the combined amount of $10.7 million, which was reflected as an increase to additional paid-in capital. The phantom equity plan is now terminated.

401(k) Plan—The Company also 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 2004, 2003 and 2002 were approximately $672, $665 and $529, respectively. Employer contributions vest ratably at 20% per year over a five year period.

7. *COMMITMENTS AND CONTINGENCIES*

The Company leases 65,000 square feet of administrative office space under an operating lease arrangement through October 31, 2010. Rental expense for 2004, 2003 and 2002 amounted to approximately $909, $1,046 and $916, respectively. A summary of future minimum lease payments under this non-cancelable operating lease as of December 31, 2004 is as follows (in thousands):

Year Ending December 31, 2005	$	1,100
Year Ending December 31, 2006		1,100
Year Ending December 31, 2007		1,100
Year Ending December 31, 2008		1,100
Year Ending December 31, 2009		1,100
Year Ending December 31, 2010		917
Total	$	6,417

The Company had a $2.5 million unused line of credit with a bank. Interest on the line of credit was prime plus one percent. The line of credit was cancelled in February 2003.

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 financial position or results of operations.

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, 2005 increased to 50% of the actual price received in excess of $20.16 per barrel. Approximately 46,000 net barrels of crude oil per month are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. During the years 2004, 2003 and 2002, the Company paid $4.8 million, $2.3 million and $0.8 million, respectively, under this agreement. As of December 31, 2004, the Company had accrued an additional $549,000 as currently payable.

Tax Separation and Indemnification Agreement with Alliant Energy—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 basis 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 basis of the Company's assets. This additional basis is 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. Future tax benefits in total will approximate $64.8 million. The Company has estimated total payments to Alliant will approximate $49.9 million given the discounting affect of the final payment in 2014. The Company has discounted all cash payments to Alliant at the date of the Tax Separation and Indemnification Agreement.

The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders' equity. The Company will monitor the estimate of when payments will be made and adjust the accretion of this liability on a prospective basis. During 2004, the Company did not make any payments under this agreement but did recognize $2.4 million of accretion expense which is included as a component of interest expense. The Company's estimate of payments to be made in 2005 under this agreement of $4,214 is reflected as a current liability at December 31, 2004.

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 change will occur during the term of this agreement.

8. *INCOME TAXES*

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax bases of assets and liabilities and amounts reported in the

Company's balance sheet. The tax effect of the net change in the cumulative temporary differences during each period in the deferred tax assets and liability determines the periodic provision for deferred taxes.

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. All income taxes receivable or payable at December 31, 2003 were to/from Alliant Energy. Section 29 tax credits of $5,363 were generated in 2002 and are expected to be utilized by Alliant Energy in the future. However, on a stand-alone basis Whiting would have been unable to use the credits in its 2002 tax return. Under the Company's tax separation and indemnification agreement with Alliant Energy, Whiting will be paid for the Section 29 credits when Alliant Energy receives the benefit for them. These credits were reported as a credit to additional paid-in capital in 2002.

Income tax expense differed from amounts computed by applying the U.S. Federal income tax rate as follows (in thousands):

	2004	2003	2002
Expected statutory tax expense at 35%	$ 39,902	$ 12,649	$ 4,183
Research tax credits	—	—	(178)
Excess percentage depletion and other	(43)	(216)	(82)
State tax expense, net of federal benefit	4,100	1,516	300
	$ 43,959	$ 13,949	$ 4,223

Temporary differences between the financial statement carrying amounts and tax bases of assets and liabilities that give rise to the net deferred tax asset or (liability) result from the following components (in thousands):

	2004	2003	2002
Oil and gas properties	$ (57,283)	$ (2,893)	$ (32,290)
Production participation plan	3,698	2,993	3,020
Available for sale securities	—	(127)	(285)
Derivative instruments	645	828	1,320
Tax sharing agreement	12,036	11,028	—
Abandonment obligations	9,356	3,028	—
Net operating loss carryforward	—	3,878	—
Other	(365)	—	—
Total net deferred income tax (liability) asset	(31,913)	18,735	(28,235)
Current deferred income tax asset	2,368	—	—
Long-term deferred income tax (liability) asset	$ (34,281)	$ 18,735	$ (28,235)

The Company's net operating loss generated during the 2003 tax year was fully utilized during 2004.

9. *OIL AND GAS ACTIVITIES*

The Company's oil and gas activities are almost entirely within the United States. The Company owns a nonoperated working interest in one field in Canada that represents less than 1% of its total reserve base. Costs incurred in oil and gas producing activities are as follows (in thousands):

	2004	2003	2002
Unproved property acquisition	$ 4,401	$ 242	$ 851
Proved property acquisition	525,563	11,823	140,708
Development	74,476	40,423	23,136
Exploration	9,739	3,186	1,811
Total	614,179	55,674	166,506

During 2004 and 2003, additions to oil and gas properties of approximately $7,280 and $996 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 are summarized as follows (in thousands):

	2004	2003	2002
Proven oil and gas properties	$ 1,225,676	$ 615,764	$ 553,902
Unproven oil and gas properties	6,038	1,637	1,593
Accumulated depreciation, depletion and amortization	(242,108)	(191,488)	(152,595)
Oil and gas properties—net	$ 989,606	$ 425,913	$ 402,900

During 2003, the Company recorded an addition to oil and gas properties of approximately $10.1 million for the asset retirement costs related to the adoption of SFAS No. 143.

The following table reflects the net changes in capitalized exploratory well costs during 2004, 2003 and 2002.

	2004	2003	2002
Beginning balance at January 1	$ —	$ —	$ —
Additions to capitalized exploratory well costs pending the determination of proved reserves	6,203	2,368	420
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(2,625)	—	—
Capitalized exploratory well costs charged to expense	(641)	(2,368)	(420)
Ending balance at December 31	$ 2,937	$ —	$ —

10. ACQUISITIONS

Permian Basin Properties

On September 23, 2004, we 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 our bank credit agreement. Based on the purchase price and estimated proved reserves of 251.1 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.37 per Mcfe of proved reserves.

Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our 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 87.7 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $0.83 per Mcfe of estimated proved reserves.

Other Cash Acquisitions of Properties

Colorado and Wyoming Properties. On August 13, 2004, we acquired interests in four producing oil and gas fields in Colorado and Wyoming. The purchase price was $44.2 million in cash and was funded under our bank credit agreement. Based on the purchase price of $44.2 million and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.11 per Mcfe of estimated proved reserves.

Wyoming and Utah Properties. On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah. The purchase price was $35.0 million in cash and was funded under our bank credit agreement. Based on the purchase price of $35.0 million and estimated proved reserves of 30.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.14 per Mcfe of estimated proved reserves.

Louisiana and South Texas Properties. On August 16, 2004, we acquired interests in five fields in Louisiana and South Texas. The purchase price was $19.3 million in cash and was funded under our bank credit agreement. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.61 per Mcfe of estimated proved reserves.

Mississippi Properties. On November 3, 2004, we acquired an interest in the Lake Como field in Mississippi. The purchase price was $12.0 million in cash and was funded under our bank credit agreement. Based on the purchase price of $12.0 million and estimated proved reserves of 10.6 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.43 per Mcfe of estimated proved reserves.

Additional Permian Basin Interest. On December 31, 2004, we 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 our bank credit agreement. Based on the purchase price and estimated proved reserves of 4.1 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.72 per Mcfe of estimated proved reserves.

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

	Permian Basin	Equity Oil	All 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

The following table reflects the pro forma results of operations for the years ended December 31, 2003 and 2004 as though the above acquisitions had occurred on the first day of each period presented. The pro forma results assume that all cash acquisitions were funded with debt. The Other Cash Acquisitions column includes the three largest acquisitions described above as the Colorado and Wyoming Properties, the Wyoming and Utah Properties and the Louisiana and South Texas Properties. The pro forma amounts for the year ended December 31, 2004 include only the activity from the beginning of the period to the closing date of the acquisitions. (in thousands, except per share amounts):

	Historical Whiting	Pro Forma Permian Basin	Pro Forma Equity Oil	Pro Forma Other Cash Acquisitions	Pro Forma Consolidated
Year ended December 31, 2003:					
Total revenues	$ 167,381	$ 91,246	$ 27,825	$ 28,592	$ 315,044
Net income before cumulative change in accounting principle	22,190	19,028	6,050	3,823	51,091
Net income	18,285	19,028	6,050	3,823	47,186
Net income per common share-basic and diluted	0.87	0.91	0.29	0.18	2.25
Year ended December 31, 2004:					
Total revenues	$ 282,140	$ 58,443	$ 15,980	$ 23,553	$ 380,116
Net income	70,046	11,614	4,047	4,457	90,164
Net income per common share-basic and diluted	3.38	0.56	0.19	0.21	4.34

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

The estimate of proved reserves and related valuations were based upon the reports of Ryder Scott Company L.P., and Cawley, Gillespie & Associates, Inc. and R. A. Lenser & Associates, Inc., each independent petroleum and geological engineers, and the Company's engineering staff, in accordance with the provisions of Statement of Financial Accounting Standards No. 69 ("SFAS No. 69"), Disclosures about Oil and Gas Producing Activities. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Substantially all of the Company's oil and gas reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil and gas reserves for the years ended December 31, 2004, 2003 and 2002, are as follows:

	Oil (MBbls)	Gas (MMcf)
Balance—January 1, 2002	14,805	227,521
Extensions and discoveries	473	2,346
Sales of minerals in place	—	(953)
Purchases of minerals in place	15,244	58,381
Production	(2,319)	(21,366)
Revisions to previous estimates	1,255	(29,941)
Balance—December 31, 2002	29,458	235,988
Extensions and discoveries	2,327	17,097
Sales of minerals in place	—	—
Purchases of minerals in place	822	3,996
Production	(2,594)	(21,596)
Revisions to previous estimates	4,627	(4,474)
Balance—December 31, 2003	34,640	231,011
Extensions and discoveries	5,175	29,133
Sales of minerals in place	—	(70)
Purchases of minerals in place	52,288	114,715
Production	(3,662)	(25,071)
Revisions to previous estimates	(853)	(9,862)
Balance—December 31, 2004	87,588	339,856
Proved developed reserves:		
December 31, 2002	23,784	167,618
December 31, 2003	26,157	171,881
December 31, 2004	60,625	242,662

As discussed in "Note 6—Employee Benefit Plans," all of the Company's employees participate in the Company's production participation plan. The reserve disclosures above include oil and gas reserve volumes that have been allocated to the production participation plan. Once allocated to plan participants, the interests are fixed. Allocations prior to 1995 consisted of 2%–3% overriding royalty interest while allocations since 1995 have been 2%–5% of net income from the oil and gas production allocated to the plan.

The above volumes include one field in Canada with total estimated proved reserves of 5.8 Bcfe and a pre-tax PV10% value of $13.2 million.

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

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

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

	2004	2003	2002
Future cash flows	$ 5,445,781	$ 2,297,935	$ 1,854,886
Future production costs	(1,804,161)	(879,390)	(677,146)
Future development costs	(216,864)	(66,326)	(65,440)
Future income tax expense	(996,035)	(336,165)	(270,516)
Future net cash flows	2,428,721	1,016,054	841,784
10% annual discount for estimated timing of cash flows	(1,116,667)	(426,490)	(365,755)
Standardized measure of discounted future net cash flows	$ 1,312,054	$ 589,564	$ 476,029

Future cash flows as shown above were reported without consideration for the effects of hedging transactions outstanding at each period end. If the effects of hedging transactions were included in the computation, then future cash flows would have decreased by $0 in 2004, $145 in 2003 and $1,300 in 2002.

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

	2004	2003	2002
(in thousands)			
Beginning of year	$ 589,564	$ 476,029	$ 211,735
Sale of oil and gas produced, net of production costs	(210,052)	(121,827)	(80,337)
Sales of minerals in place	(122)	—	(739)
Net changes in prices and production costs	174,511	108,115	212,191
Extensions, discoveries and improved recoveries	153,444	47,183	6,587
Development costs-net	(150,537)	(886)	(11,328)
Purchases of mineral in place	973,959	16,745	241,798
Revisions of previous quantity estimates	(33,999)	43,679	(36,164)
Net change in income taxes	(343,023)	(42,082)	(116,854)
Accretion of discount	78,462	62,901	24,786
Changes in production rates and other	79,847	(293)	24,354
End of year	$ 1,312,054	$ 589,564	$ 476,029

Average wellhead prices in effect at December 31, 2004, 2003 and 2002 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows (in thousands):

	2004	2003	2002
Oil (per Bbl)	$ 40.58	$ 29.43	$ 28.21
Gas (per Mcf)	$ 5.56	$ 5.52	$ 4.39

12. *QUARTERLY FINANCIAL DATA (UNAUDITED)*

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2004 and 2003 (in thousands except per share data) (in thousands):

	Three Months Ended			
	March 31, 2004	June 30, 2004	September 30, 2004	December 31, 2004
Year ended December 31, 2004:				
Oil and gas sales	$ 47,636	$ 52,874	$ 65,898	$ 114,649
Net income	9,638	13,471	14,317	32,620
Basic and diluted net income per share	0.51	0.72	0.70	1.31

	Three Months Ended			
	March 31, 2004	June 30, 2004	September 30, 2004	December 31, 2004
Year ended December 31, 2003:				
Oil and gas sales	$ 49,483	$ 41,883	$ 42,272	$ 42,093
Income (loss) before income tax and cumulative effect of change in accounting principle	11,935	11,481	12,885	(162)
Cumulative effect of change in accounting principle	(3,905)	—	—	—
Net income (loss)	3,559	7,053	7,989	(316)
Basic and diluted net income (loss) per share	0.19	0.38	0.43	(0.02)

13. SUBSEQUENT EVENT (UNAUDITED)

On February 23, 2005, Whiting announced that it had entered into a purchase and sale agreement to acquire operated interests in five producing gas fields in the Green River Basin of Wyoming. The purchase price will be $65.0 million, or $1.29 per Mcfe, for estimated proved reserves of 50.5 Bcfe. Whiting will operate approximately 95% of the net daily production from the properties which is currently 6.3 MMcfe/d. The purchase and sale agreement is subject to standard conditions to closing, including Whiting's completion of title and environmental due diligence, with closing expected by the end of March 2005. The acquisition will be funded under Whiting's credit agreement.

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

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of the end of the year ended December 31, 2004. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of the end of the year ended December 31, 2004 to ensure that (a) information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (b) material information relating to us, including our consolidated subsidiaries, was made known to them by others within those entities, particularly during the period in which this Annual Report on Form 10-K was being prepared.

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

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

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended December 31, 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

On February 24, 2005, our Board of Directors approved changes to the compensation we pay to our non-employee directors that became effective February 24, 2005 and are set forth in Exhibit 10.5 to this Annual Report on Form 10-K, which is incorporated by reference into this Item 9B.

On February 24, 2005, the Compensation Committee of our Board of Directors approved the allocation under our Production Participation Plan of net revenue interests to our executive officers in oil and natural gas wells acquired or developed during 2004 . The aggregate allocation of net revenue interests in such wells for the 2004 plan year was set by the Board of Directors at 2.5%, and of this aggregate amount James J. Volker was awarded 5.3%, each of D. Sherwin Artus, James R. Casperson, James T. Brown, J. Douglas Lang, Patricia J. Miller, Mark R. Williams and Michael J. Stevens were awarded 3.5% and David M. Seery was awarded 0.6% by the Compensation Committee. Once allocated, such interests (not legally conveyed) are fixed and all payments are pursuant to the terms of the Production Participation Plan.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information included under the captions "Election of Directors," "Board of Directors and Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance", respectively, in our definitive Proxy Statement for Whiting Petroleum Corporation's 2005 Annual Meeting of Stockholders (the "Proxy Statement") is hereby incorporated herein by reference. Information with respect to our executive officers appears in Part I of this Annual Report on Form 10-K.

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

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

Item 11. Executive Compensation

The information required by this Item is included under the captions "Board of Directors and Corporate Governance – Director Compensation" and "Executive Compensation" in the Proxy Statement and is hereby incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The information required by this Item with respect to security ownership of certain beneficial owners and management is included under the caption "Principal Stockholders" in the Proxy Statement and is hereby incorporated by reference.

The following table sets forth information with respect to compensation plans under which equity securities of Whiting Petroleum Corporation are authorized for issuance as of December 31, 2004.

Plan Category	Number of securities to be issued upon the exercise of outstanding options warrants and rights	Weighted-average exercise price of outstanding options warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders(1)	—	N/A	1,894,803(2)
Equity compensation plans not approved by security holders	—	N/A	—
Total	—	N/A	1,894,803(2)

(1) Includes only the Whiting Petroleum Corporation 2003 Equity Incentive Plan.
(2) Excludes 105,197 shares of restricted common stock previously issued and outstanding for which the restrictions have not lapsed.

Item 13. Certain Relationships and Related Transactions

Not applicable.

Item 14. Principal Accounting Fees and Services

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

PART IV

Item 15. Exhibits, Financial Statement Schedules

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

a. Report of Independent Registered Public Accounting Firm

b. Consolidated Balance Sheets as of December 31, 2004 and 2003

c. Consolidated Statements of Income for the Years ended December 31, 2004, 2003 and 2002

d. Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Years ended December 31, 2004, 2003 and 2002

e. Consolidated Statements of Cash Flows for the Years ended December 31, 2004, 2003 and 2002

f. Notes to Consolidated Financial Statements

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

a. Schedule I – Condensed Financial Information of Registrant

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

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

(b) Exhibits

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

(c) Financial Statement Schedules.

WHITING PETROLEUM CORPORATION

CONDENSED FINANCIAL INFORMATION OF REGISTRANT
BALANCE SHEETS
AS OF DECEMBER 31, 2004 AND 2003

(In thousands, except share data)

	2004	2003
ASSETS		
CURRENT ASSETS:		
Deferred income taxes	$ 2,368	$ —
LONG-TERM ASSETS:		
Investment in subsidiaries	480,841	272,650
Intercompany receivable	343,411	—
Debt issue cost	4,772	—
Deferred income taxes	—	18,735
TOTAL	$ 831,392	$ 291,385
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 1,400	$ —
Current portion of long-term debt	3,167	—
Total current liabilities	4,567	—
LONG-TERM DEBT	148,978	3,017
TAX SHARING LIABILITY	31,180	28,790
DEFERRED INCOME TAXES	34,281	—
STOCKHOLDERS' EQUITY:		
Common stock, $.001 par value; 75,000,000 shares authorized, 29,717,808 and 18,750,000 shares issued and outstanding as of December 31, 2004 and 2003, respectively	30	19
Additional paid-in capital	455,635	170,367
Accumulated other comprehensive loss	(1,025)	(223)
Deferred compensation	(1,715)	—
Retained earnings	159,461	89,415
Total stockholders' equity	612,386	259,578
TOTAL	$ 831,392	$ 291,385

See notes to condensed financial information of registrant.

WHITING PETROLEUM CORPORATION

CONDENSED FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2004 AND THE PERIOD FROM NOVEMBER 25, 2003 TO DECEMBER 31, 2003

(In thousands)

	2004	2003
OPERATING EXPENSES:		
General and administrative	$ (580)	$ —
INTEREST EXPENSE	(8,998)	(220)
EQUITY IN EARNINGS (LOSSES) OF SUBSIDIARIES	123,583	(7,436)
INCOME (LOSS) BEFORE INCOME TAXES	114,005	(7,656)
INCOME TAX EXPENSE (BENEFIT)	43,959	(2,955)
NET INCOME (LOSS)	$ 70,046	$ (4,701)

See notes to condensed financial information of registrant.

WHITING PETROLEUM CORPORATION

CONDENSED FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2004 AND THE PERIOD FROM NOVEMBER 25, 2003 TO DECEMBER 31, 2003

(In thousands)

	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 70,046	$ (4,701)
Equity in (earnings) losses of subsidiaries	(123,583)	7,436
Deferred income taxes	40,077	(2,955)
Amortization of debt issuance costs and debt discount	501	—
Amortization of deferred compensation	580	—
Accretion of tax sharing agreement	2,390	220
Change in other current liabilities	1,550	—
Net cash provided by operating activities	(8,439)	—
CASH FLOWS FROM INVESTING ACTIVITIES:		
Investment in subsidiaries	(31,541)	—
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	239,686	—
Issuance of 7¼% Senior Subordinated Notes due 2012	148,890	—
Intercompany receivable	(343,411)	—
Debt issuance costs	(5,185)	—
Net cash provided by financing activities	39,980	—
NET CHANGE IN CASH AND CASH EQUIVALENTS	—	—
CASH AND CASH EQUIVALENTS:		
Beginning of period	—	—
End of period	$ —	$ —

See notes to condensed financial information of registrant.

NOTES TO CONDENSED FINANCIAL INFORMATION OF REGISTRANT
FOR THE YEAR ENDED DECEMBER 31, 2004 AND THE PERIOD FROM NOVEMBER 25, 2003 TO DECEMBER 31, 2003

1. GENERAL

Whiting Petroleum Corporation, formerly known as Whiting Petroleum Holdings, Inc. (the "Company"), was incorporated in the state of Delaware on July 18, 2003. The Company was formed for the sole purpose of becoming a holding company of Whiting Oil and Gas Corporation, formerly known as Whiting Petroleum Corporation ("Whiting Oil and Gas"). Whiting Oil and Gas is an oil and gas exploration and development company that was, until November 25, 2003, a wholly owned subsidiary of Alliant Energy Resources, Inc. ("Resources"). On November 25, 2003, the Company completed an initial public offering of its common stock (the "IPO"). Immediately prior to the IPO, Resources transferred all of the outstanding stock of Whiting Oil and Gas to the Company in exchange for 18,330,000 shares of common stock issued by the Company, which constituted all of the Company's outstanding stock, and a promissory note in the aggregate principal amount of $3.0 million. Resources then sold 17,250,000 shares of the Company's common stock in the IPO. Prior to November 25, 2003, the Company conducted no activities other than its formation and held no assets. As a result, financial statements for the Company for periods prior to November 25, 2003 are not presented as part of the accompanying condensed financial statements of the Company.

The accompanying condensed financial statements of the Company should be read in conjunction with the consolidated financial statements of the Company and its subsidiaries included in the Company's Annual Report on Form 10-K for the year ended December 31, 2004.

2. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2004 and 2003:

	2004	2003
7 ¼% Senior Subordinated Notes due 2012	$ 148,978	$ —
Alliant Energy	3,167	3,017
Total	152,145	3,017
Current portion of long-term debt	(3,167)	—
Long-term debt	$ 148,978	$ 3,017

7 ¼% Senior Subordinated Notes due 2012—In May 2004, the Company issued, in a private placement, $150.0 million aggregate principal amount of its 7 1/4% senior subordinated notes due 2012. The net proceeds of the offering were used to refinance debt outstanding under the Company's credit agreement. 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 the Company and are subordinated to all of the Company's senior debt. The indenture governing the notes contains various restrictive covenants that 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 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 limit the discretion of the Company's management in operating the Company's business. In addition, Whiting Oil and Gas Corporation's credit agreement restricts the ability of the Company's subsidiaries to make payments to the Company. The Company was in compliance with these covenants as of December 31, 2004. Three of the Company's subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company (the "Guarantors"), have fully, unconditionally, jointly and severally guaranteed the Company's obligations under the notes. All of the Company's subsidiaries other than the Guarantors are minor within the meaning of Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission, and the Company has no independent assets or operations. Based on the market price of the 7 1/4% senior subordinated notes due 2012, their estimated fair value was $157.1 million as of December 31, 2004.

Short-Term Debt—In conjunction with the Company's initial public offering in November 2003, the Company issued a promissory note payable to Alliant Energy in the aggregate principal amount of $3.0 million. The promissory note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due on November 25, 2005.

3. *COMMITMENTS AND CONTINGENCIES*

The Company leases 65,000 square feet of administrative office space under an operating lease arrangement through October 31, 2010. Rental expense for 2004, 2003 and 2002 amounted to approximately $909, $1,046 and $916, respectively. A summary of future minimum lease payments under this non-cancelable operating lease as of December 31, 2004 is as follows (in thousands):

Year Ending December 31, 2005	$	1,100
Year Ending December 31, 2006		1,100
Year Ending December 31, 2007		1,100
Year Ending December 31, 2008		1,100
Year Ending December 31, 2009		1,100
Year Ending December 31, 2010		917
Total	$	6,417

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 financial position or results of operations.

Tax Separation and Indemnification Agreement with Alliant Energy—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 basis 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 basis of the Company's assets. This additional basis is 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. Future tax benefits in total will approximate $64.8 million. The Company has estimated total payments to Alliant will approximate $49.9 million given the discounting affect of the final payment in 2014. The Company has discounted all cash payments to Alliant at the date of the Tax Separation and Indemnification Agreement.

The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders' equity. The Company will monitor the estimate of when payments will be made and adjust the accretion of this liability on a prospective basis. During 2004, the Company did not make any payments under this agreement but did recognize $2.4 million of accretion expense which is included as a component of interest expense. The Company's estimate of payments to be made in 2005 under this agreement of $4,214 is reflected as a current liability at December 31, 2004.

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 change will occur during the term of this agreement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 28th day of February, 2005.

WHITING PETROLEUM CORPORATION

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

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

Signature	Title	Date
/s/ James J. Volker James J. Volker	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2005
/s/ James R. Casperson James R. Casperson	Vice President of Finance and Chief Financial Officer (Principal Financial Officer)	February 28, 2005
/s/ Michael J. Stevens Michael J. Stevens	Controller and Treasurer (Principal Accounting Officer)	February 28, 2005
/s/ Thomas L. Aller Thomas L. Aller	Director	February 28, 2005
/s/ Graydon D. Hubbard Graydon D. Hubbard	Director	February 28, 2005
/s/ J. B. Ladd J. B. Ladd	Director	February 28, 2005
/s/ Palmer L. Moe Palmer L. Moe	Director	February 28, 2005
/s/ Kenneth R. Whiting Kenneth R. Whiting	Director	February 28, 2005

EXHIBIT INDEX

Exhibit Number	Exhibit Description
(3.1)	Amended and Restated Certificate of Incorporation of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(3.2)	Amended and Restated By-laws of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.2 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the fiscal year ended December 31, 2003 (File No. 001-31899)].
(4.1)	Second Amended and Restated Credit Agreement, dated as of September 23, 2004, among Whiting Oil and Gas Corporation, Whiting Petroleum Corporation, the financial institutions listed therein and Bank One, NA, as Administrative Agent [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 23, 2004 (File No. 001-31899)].
(4.2)	Indenture, dated May 11, 2004, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and J.P. Morgan Trust Company, National Association [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 (File No. 001-31899)].
(10.1)*	Whiting Petroleum Corporation 2003 Equity Incentive Plan [Incorporated by reference to Exhibit 10.11 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.2)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's quarterly Report on Form 10-Q for the quarter ended September 30, 2004 (File No. 001-31899)].
(10.3)*	Whiting Oil and Gas Corporation Production Participation Plan, as amended and restated [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 (File No. 001-31899)].
(10.4)	Tax Separation and Indemnification Agreement between Alliant Energy Corporation, Whiting Petroleum Corporation and Whiting Oil and Gas Corporation [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.5)*	Summary of 2005 Non-Employee Director Compensation for Whiting Petroleum Corporation.
(21)	Subsidiaries of Whiting Petroleum Corporation.
(23.1)	Consent of Deloitte & Touche LLP.
(23.2)	Consent of Cawley, Gillespie & Associates, Inc., Independent Petroleum Engineers.
(23.3)	Consent of R.A. Lenser & Associates, Inc., Independent Petroleum Engineers.
(23.4)	Consent of Ryder Scott Company, L.P., Independent Petroleum Engineers.
(31.1)	Certification by Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President of Finance and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Certification of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350
(32.2)	Certification of the Vice President of Finance and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
(99.1)	Proxy Statement for the 2005 Annual Meeting of Stockholders, to be filed within 120 days of December 31, 2004 [To be filed with the Securities and Exchange Commission under Regulation 14A within 120 days after December 31, 2004; except to the extent specifically incorporated by reference, the Proxy Statement for the 2005 Annual Meeting of Stockholders shall not be deemed to be filed with the Securities and Exchange Commission as part of this Annual Report on Form 10-K]

* A management contract or compensatory plan or arrangement.

Exhibit 21

SUBSIDIARIES OF WHITING PETROLEUM CORPORATION

Name	Jurisdiction of Incorporation or Organization	Percent Ownership
Whiting Oil and Gas Corporation	Delaware	100%
Equity Oil Company	Colorado	100%
Whiting Programs, Inc.	Delaware	100%
Whiting-Park Production Partnership, Ltd.	Texas	16%
Whiting-Madison Production Partnership, Ltd.	Texas	16%
Whiting 1988 Production Limited Partnership, Ltd.	Texas	13%

CERTIFICATIONS

I, James J. Volker, Chairman, President and Chief Executive Officer of Whiting Petroleum Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K of Whiting Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2005

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

Exhibit 31.2

CERTIFICATIONS

I, James R. Casperson, Vice President of Finance and Chief Financial Officer of Whiting Petroleum Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K of Whiting Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2005

/s/ James R. Casperson
James R. Casperson
Vice President of Finance and Chief Financial Officer

Exhibit 32.1

WRITTEN STATEMENT OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350

Solely for the purposes of complying with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, the undersigned Chairman, President and Chief Executive Officer of Whiting Petroleum Corporation, a Delaware corporation (the "Company"), hereby certify, based on my knowledge, that the Annual Report on Form 10-K of the Company for the fiscal year ended December 31, 2004 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

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

Dated: February 28, 2005

Exhibit 32.2

WRITTEN STATEMENT OF THE CHIEF FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350

Solely for the purposes of complying with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, the undersigned Vice President of Finance and Chief Financial Officer of Whiting Petroleum Corporation, a Delaware corporation (the "Company"), hereby certify, based on my knowledge, that the Annual Report on Form 10-K of the Company for the fiscal year ended December 31, 2004 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ James R. Casperson
James R. Casperson
Vice President of Finance and Chief Financial Officer

Dated: February 28, 2005

EXECUTIVE OFFICERS

James J. Volker
Chairman of the Board, President,
Chief Executive Officer

D. Sherwin Artus
Senior Vice President

James R. Casperson[1]
Vice President-Finance, Chief Financial Officer

James T. Brown
Vice President, Operations

Mark R. Williams
Vice President, Exploration and Development

Bruce R. DeBoer
Vice President, General Counsel and Secretary

Patricia J. Miller
Vice President, Human Resources

Michael J. Stevens[1]
Controller and Treasurer

J. Douglas Lang
Vice President, Reservoir Engineering and Acquisitions

David M. Seery
Vice President, Land

[1] Mr. Casperson will resign as Vice President-Finance, Chief Financial Officer and Mr. Stevens will be appointed as Vice President, Chief Financial Officer both effective March 1, 2005.

BOARD OF DIRECTORS

	Director Since
James J. Volker President, Chairman of the Board, Chief Executive Officer	2002
Thomas L. Aller President Interstate Power and Light Company, an Alliant Energy Company	1997
Graydon D. Hubbard* + ^ Retired Certified Public Accountant	2003
J.B. Ladd* + Independent Oil and Natural Gas Operator	1980
Kenneth R. Whiting+ ^ Founder Whiting Petroleum Corporation	1980
Palmer Moe* ^ Managing Director Kronkosky Charitable Foundation Past President Valero Energy Corporation	2004

* Audit Committee
\+ Compensation Committee
^ Nominating and Governance Committee

CORPORATE OFFICES

Whiting Petroleum Corporation
1700 Broadway, Suite 2300
Denver, Colorado 80290-2300
Tel: (303) 837-1661 Fax: (303) 861-4023
www.whiting.com

INVESTOR RELATIONS

Securities analysts, investors and the financial media should contact:
G. Mark Burford
Director, Investor Relations
Tel: (303) 837-1661

TRANSFER AGENT

Please direct communication regarding individual stock records and address changes to:
Computershare Trust Company, Inc.
350 Indiana Street, Suite 800
Golden, Colorado 80401
Tel: (303) 262-0600 Fax: (303) 262-0700
www.computershare.com

STOCK EXCHANGE LISTING

New York Stock Exchange, trading symbol: WLL

PETROLEUM CONSULTANTS

Cawley Gillespie & Associates, Inc.
R.A. Lenser & Associates, Inc.
Ryder Scott Company

INDEPENDENT AUDITORS

Deloitte & Touche LLP

INFORMATION UPDATES

Whiting's quarterly financial results and other information are available on our website at www.whiting.com

ANNUAL REPORT ON FORM 10-K

Upon request, the Company will provide without charge, copies of the 2004 Annual Report on Form 10-K as filed with the Securities and Exchange Commission.

ANNUAL MEETING

Tuesday, May 10, 2005 at 9:00 A.M.
Wells Fargo Center – John D. Hershner Room
1700 Lincoln Street, Denver, Colorado

CERTIFICATIONS

The Company has filed as exhibits to its Annual Report on Form 10-K for the fiscal year ended December 31, 2004 the certifications of its Chief Executive Officer and Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act. The Company submitted to the New York Stock Exchange during 2004 the Annual CEO Certification required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

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