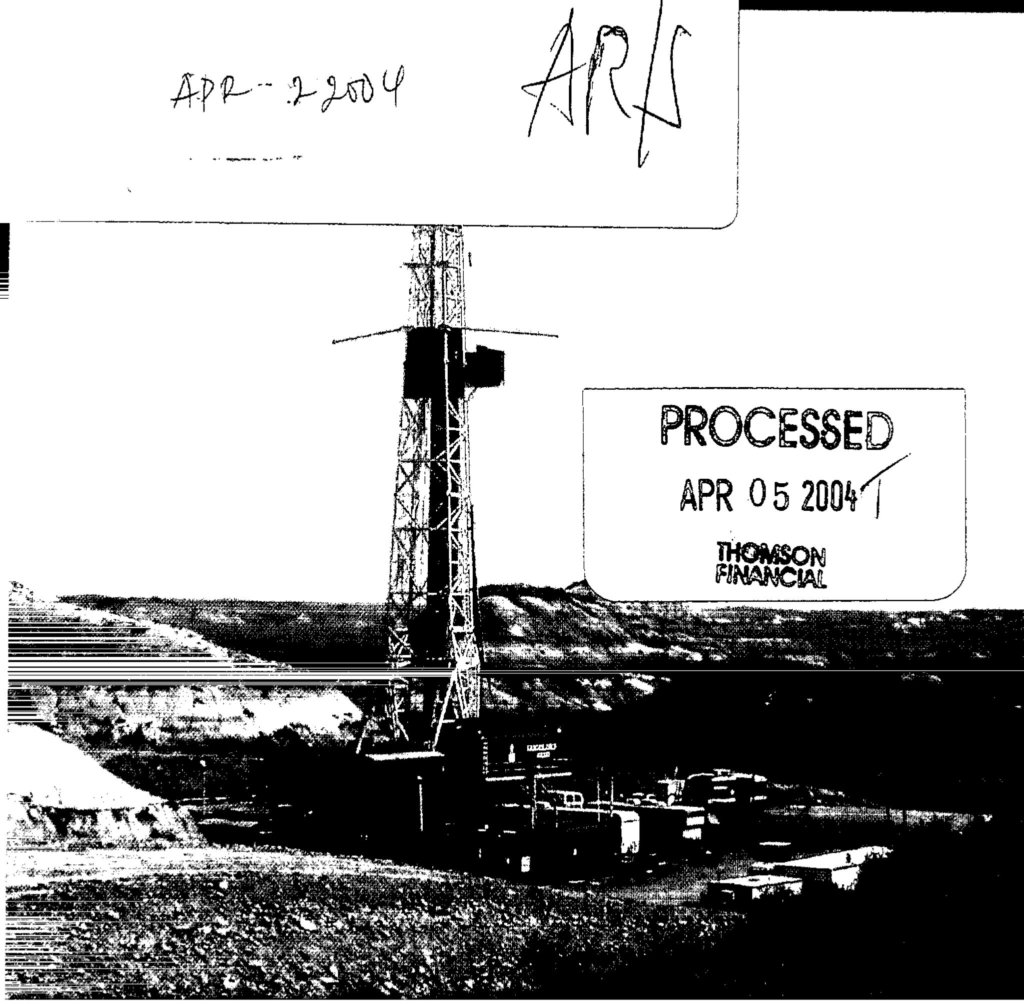
WHITING PETROLEUM CORPORATION

2003 ANNUAL REPORT



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

1992 Acquired by Alliant Energy for $27.5MM

1999 Proved reserves totaled 194 Bcfe at year-end

2000 Initiated Big Up plan to grow Whiting, invested $139MM

2001 Invested $100MM
Purchased operating interest in five Edwards Lime Fields

2002 Invested $165MM
Purchased operating interest in Big Stick and North Elkhorn Ranch
Purchased operating interest Agua Dulce Field

2003 Completed IPO in November 2003 at $15.50 per share
Recorded company-record oil and gas revenue of $175.7MM
Recorded company-record production of 37.2 Bcfe
Posted record reserves of 438.8 Bcfe
Replaced 170% of 2003 production
Reduced debt-to-capitalization ratio to 42%
Closed 2003 with stock price at $18.40, up 18.7% since IPO

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This annual report contains forward-looking statments. These statements should be considered in light of the disclaimer set forth on page 22 of the enclosed Annual Report on Form 10-K.

OUR STRATEGY: ACQUIRE, EXPLOIT AND EXPLORE

We expect that Whiting Petroleum Corporation's growth will come from increasing our reserve base. We continually look to add to our daily production through complementary acquisitions, efficiently exploiting our undeveloped oil and natural gas reserves and drilling a number of exploratory wells in our Gulf Coast/Permian Basin, Rocky Mountain, Michigan and Mid-Continent regions. As of December 31, 2003, we owned reserves of 438.8 Bcfe. Our 2003 average daily production rate was 102 MMcfe. We operate 838 properties located across all our operating regions. According to a September 2003 study by *Oil & Gas Journal*, Whiting Petroleum's total assets make it the 54th largest publicly traded exploration and production company with operations in the United States.

Whiting's growth strategy is founded upon the combination of property acquisitions, exploitation and exploration. For the four-year period ended December 31, 2003, Whiting's proved reserves increased from 194 Bcfe to 438.8 Bcfe, an average annual increase of 31.5%. For the year 2003, our all-in finding cost was $0.86 per Mcfe. Our low finding and development cost, by industry standards, is a mark of a disciplined acquisition and development strategy.

We project that our 2004 daily production exit rate will be approximately 10% greater than 2003's company-record average of 102 MMcfe. Much of our future growth results from having an average of 82% working interest control of our proved undeveloped drilling inventory. Whiting's 2004 drilling capital budget of $68 million is split approximately as follows:

- $33 million for the development of our proved undeveloped reserves;

- $35 million for the drilling of exploration prospects and development of currently unproven reserves.

Acquisition opportunities would increase the capital budget. Whiting is always evaluating new properties for acquisition.

FRONT COVER PHOTO

Drilling operations on the Big Stick Madison Unit #25-06 in the Big Stick Field, Billings County, ND

FINANCIAL & OPERATIONS SUMMARY

	2003	2002	2001	2000
(Dollars in Thousands, Except per Share or Ratio Amounts)				
INCOME STATEMENT AND CASH FLOW				
Oil and Gas Sales	$ 175,731	$ 122,709	$ 125,286	$ 107,004
Net Income	$ 18,285	$ 7,729	$ 41,243	$ 33,661
Net Income per Share	$ 0.98	$ 0.41	$ 2.20	$ 1.80
Shares Outstanding (Basic and Diluted)	18,750	18,750	18,750	18,750
Net Cash Provided by Operating Activities	$ 96,362	$ 62,581	$ 62,347	$ 42,278
Net Cash Used in Investing Activities	$ (52,008)	$ (157,475)	$ (86,485)	$ (109,668)
Net Cash Provided by Financing Activities	$ 4,398	$ 98,710	$ 23,869	$ 63,125
BALANCE SHEET				
Total Assets	$ 536,285	$ 448,468	$ 319,836	$ 256,382
Long-Term Debt	$ 188,017	$ 265,472	$ 163,591	$ 139,722
Stockholders' Equity	$ 259,578	$ 122,818	$ 111,467	$ 70,048
Debt-to-Capitalization Ratio	42%	68%	59%	67%
RESERVES				
Oil, MBbl	34,640	29,458	14,805	19,121
Natural Gas, MMcf	231,011	235,988	227,521	157,521
Reserves, MMcfe	438,851	412,736	316,351	272,247
Reserves to Production Ratio	11.8	11.7	9.8	10.4
Average Wellhead Oil Price per Bbl in Reserve Report	$ 29.43	$ 28.21	$ 17.30	$ 24.04
Average Wellhead Gas Price per Mcfe in Reserve Report	$ 5.52	$ 4.39	$ 2.72	$ 9.18
Estimated Future Net Revenues, Before Income Taxes	$ 1,352,200	$ 1,112,400	$ 425,600	$ 1,356,000
Present Value at 10%, Before Income Taxes	$ 784,600	$ 638,600	$ 244,600	$ 728,300
Present Value at 10%, After Income Taxes	$ 589,600	$ 476,000	$ 211,700	$ 519,200
PRODUCTION AND COMMODITY PRICES				
Oil Production, MBbl	2,594	2,319	2,088	1,561
Natural Gas Production, MMcf	21,596	21,366	19,751	16,905
Production, MMcfe	37,160	35,280	32,279	26,271
Oil Sales Price, per Bbl Average	$ 27.50	$ 23.35	$ 23.85	$ 26.96
Natural Gas Sales Price, per Mcf Average	$ 4.78	$ 3.21	$ 3.82	$ 3.51
Average Sales Price, per Mcfe	$ 4.73	$ 3.48	$ 3.88	$ 4.07
Lease Operating Expense, per Mcfe	$ 1.16	$ 0.93	$ 0.92	$ 0.90
Production Tax Expense, per Mcfe	$ 0.29	$ 0.21	$ 0.20	$ 0.20

12/31/03 OPERATING INVENTORY	Gross	Net
Total Wells	5,006	1,350
Total Operated Wells	838	600
Developed Acreage	516,500	205,800
Undeveloped Acreage	385,800	188,300

Opposite page: production facilities, Sioux Field, McKenzie County, ND

(Dollars in Thousands)

CALCULATION OF FINDING, DEVELOPMENT & ACQUISITION COSTS

	2003	2002	2001	2000	Four-Year Total
Capital Expenditures, Per Consolidated Statement of Cash Flows	$ 52,008	$ 165,443	$ 99,621	$ 139,135	$ 456,207
Furniture and Fixture Additions	$ (516)	$ (748)	$ (1,419)	$ -	$ (2,683)
Exploration Costs	$ 3,186	$ 1,811	$ 793	$ 1,410	$ 7,200
Acquisition and Development Costs	$ 54,678	$ 166,506	$ 98,995	$ 140,545	$ 460,724
Reserve Additions, Including Revisions, MMcfe	63,275	132,618	86,490	119,630	402,013
FD&A Cost per Mcfe	$ 0.86	$ 1.26	$ 1.14	$ 1.17	$ 1.15

CALCULATION OF RESERVE REPLACEMENT PERCENTAGE

	2003	2002	2001	2000	Four-Year Total
Reserve Additions, Including Revisions, MMcfe	63,275	132,618	86,490	119,630	402,013
Production of Oil and Natural Gas, MMcfe	37,160	35,280	32,279	26,271	130,990
Reserve Replacement Percentage	170%	376%	268%	455%	307%

PRESIDENT'S MESSAGE

I want to welcome you as new fellow shareholders of Whiting Petroleum Corporation. We are the first oil and gas company to complete an initial public offering in our business in nearly two years. Our initial public offering represents the culmination of a strategic plan we undertook at the end of 1999. In 2000, we initiated that plan, called Big Up, with the goal to increase key corporate metrics each year. Since initiating Big Up in January 2000, we've recorded a series of new company records while realizing solid growth rates:

- Reserves are up 126% – from 194.1 Bcfe at January 1, 2000 to 438.8 Bcfe at December 31, 2003
- Production increased 44% – from 25.8 Bcfe in 1999 to 37.2 Bcfe in 2003
- Oil and gas revenues rose more than 188% – from $60.9 million in 1999 to $175.7 million in 2003
- Net cash flow from operations is up 149% – from $38.7 million in 1999 to $96.4 million in 2003
- Total assets are up 261% – from $148.5 million at December 31, 1999 to $536.3 million at December 31, 2003
- Stockholders' equity rose 565% – from $39 million at December 31,1999 to $259.6 million at December 31, 2003

As a public company, we believe we are better positioned to continue this trend. We completed our initial public offering in November 2003 at $15.50 per share with a clearly defined mandate – to increase shareholder value by investing in oil and gas projects with attractive rates of return on capital employed. With the offering completed, as of March 10, 2004, Whiting Petroleum has a market capitalization of over $400 million.

ENHANCING SHAREHOLDER VALUE DURING VOLATILE TIMES

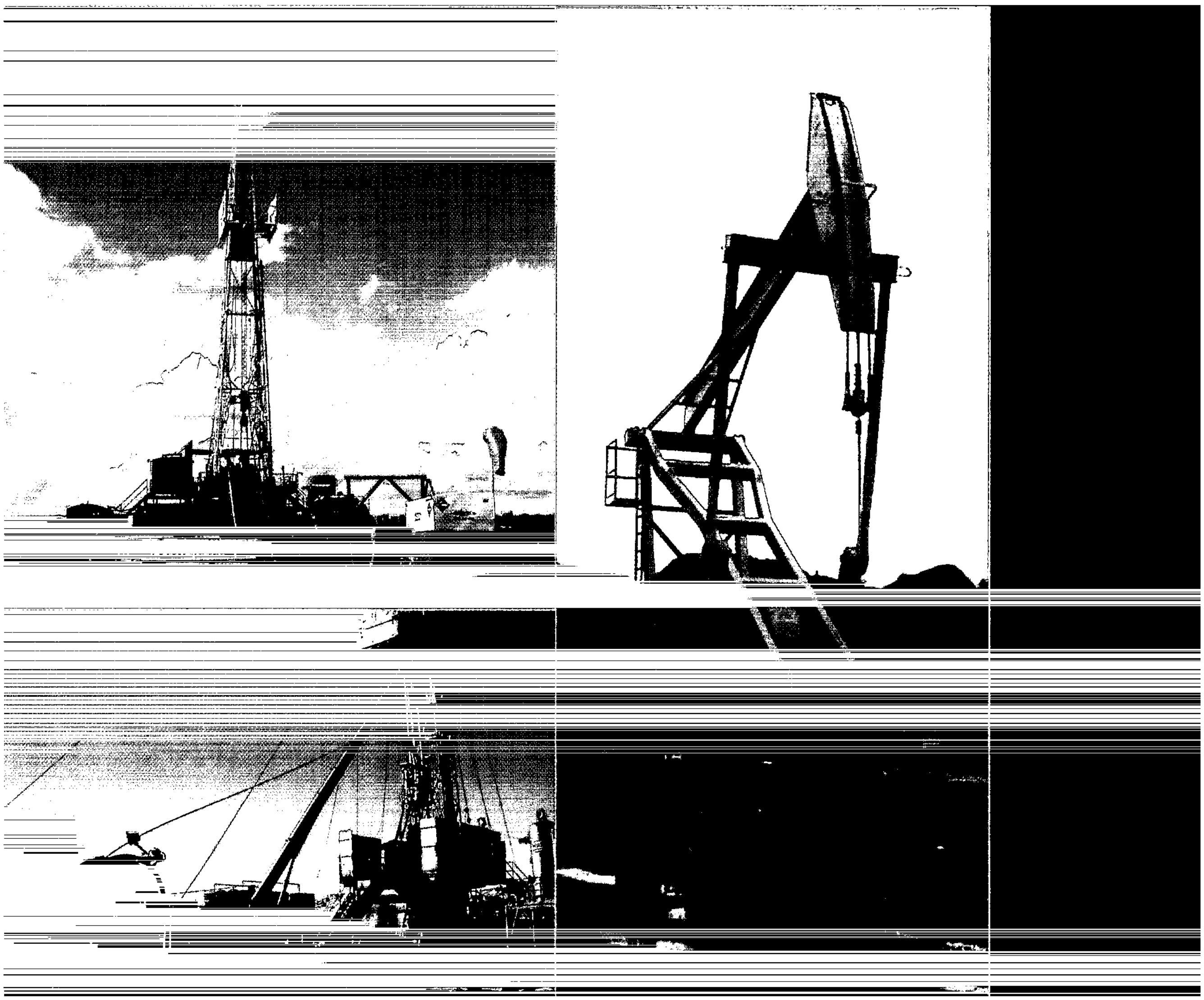
The experience we have gained during the course of our 23-year history has prepared us to manage our assets and execute our strategy during periods of oil and gas price uncertainty. It is a fundamental principle of Whiting Petroleum to use all available industry technologies to increase the underlying value of our properties. We will also sell properties when we believe the price received is greater than our internal valuation, or when the properties no longer fit our operating profile.

As crude oil and natural gas prices continue to defy accurate projection, Whiting sees more, not fewer, opportunities for growth. Over the last four years, we have purchased and developed approximately 302 Bcfe of reserves at an all-in finding and development cost of $1.15 per Mcfe[1].

During the same four year period, our realized commodity prices, on an equivalent basis, averaged $4.05 per Mcfe. With our low-cost operating platform we realized margins of about 60% of our $4.73 average price per Mcfe in 2003. We truly believe that the low-cost acquirer and producer delivers superior returns in a commodity-based business.

Opposite page, clockwise from left: drilling operations, Lynne 43-2 Wabek Field, Mountrail County, ND; pumping unit, NERU 3094 North Elkhorn Ranch Unit, Divide County, ND; completion operations, Burnett #4 Agua Dulce Field, Nueces County, TX

[1] Reconciliations of FD&A and reserve replacement rates are included on page 3.



Whiting's diversity of fields and properties limits the effect of mechanical failure or other problems in individual wells on total production and reserve quantities. There are strong signs that the economy is strengthening. Consumer confidence is up and industrial output is rising. Demand for oil and gas tracks industrial output. The Energy Information Agency predicts U.S. natural gas demand will increase to 22.19 Tcf, an increase of 1.2% in 2004, and will reach 22.6 Tcf, another increase of 1.8%, in 2005. We believe that Whiting is positioned to benefit from the strengthening economy. In December 2003, we received weighted average wellhead prices of $28.76 a barrel for our crude oil production and $4.39 per Mcf for our natural gas production. For the year 2003, our average wellhead price received per Mcfe was $4.73, a 36% increase over 2002's price of $3.48. Based on December 2003 production, our annual net cash flow from operations moves approximately $3.1 million for every $0.15 change in natural gas prices and $2.4 million when oil prices move a $1 per barrel.

OUR GROWTH PHILOSOPHY: ACQUIRE, EXPLOIT AND EXPLORE

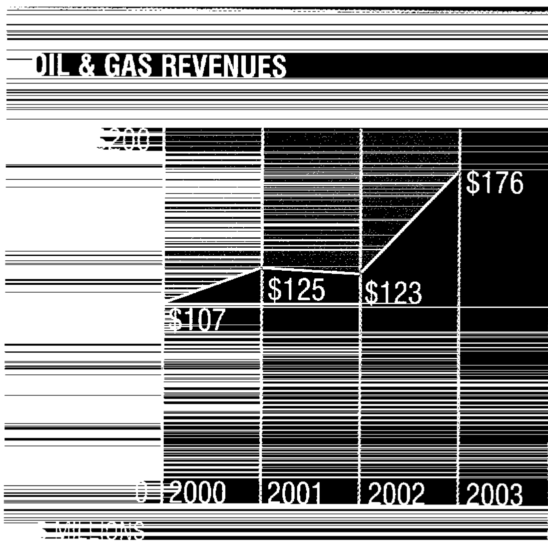
Our ongoing, active approach to acquisitions, coupled with a studied and informed program of exploitation drilling and improved recovery projects, enhances Whiting's cash flow and provides a cornerstone for growth. To be more direct, since 2000, we have achieved rapid growth and enhanced shareholder value through the execution of an operating strategy with four major elements:

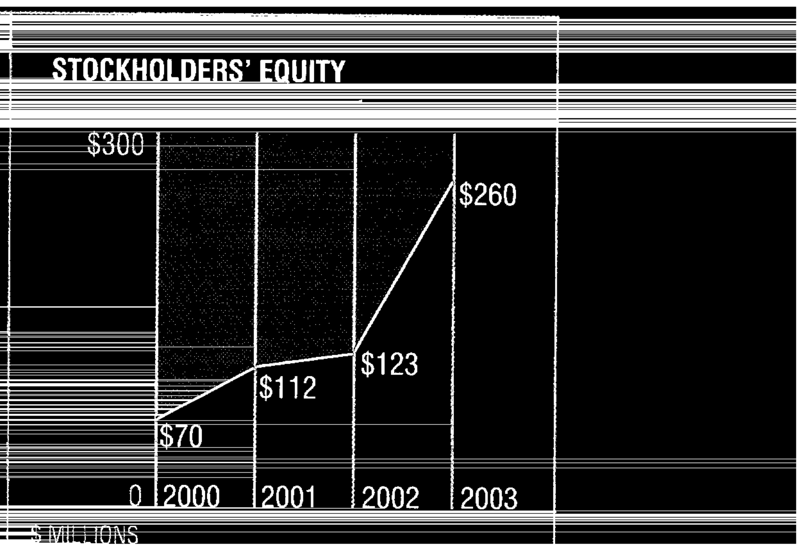
- Acquire properties with attractive rates of return on the existing proved developed producing reserves and with significant exploitation and development potential. We have three core areas: Rockies, Michigan and Gulf Coast/Permian. We attempt to concentrate our acquisitions in these core areas for greater operating efficiency.
- Increase reserves and production from existing properties through moderate-risk development drilling and enhanced production techniques.
- Annually, drill several exploratory potentially high-return, operated and non-operated properties.
- Control costs through efficient operation of existing properties by our experienced technical and field-level personnel.

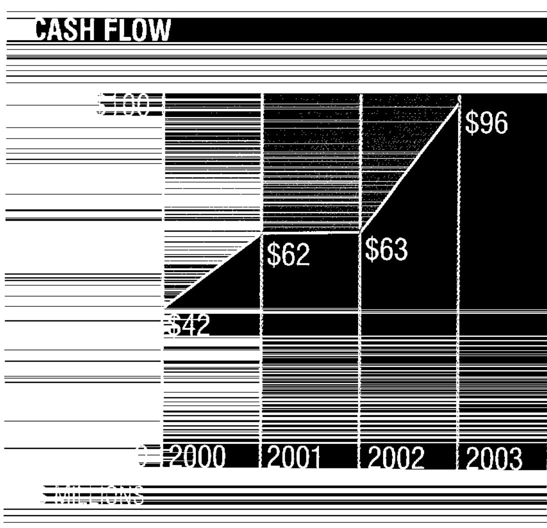
OUR 2003 RESULTS

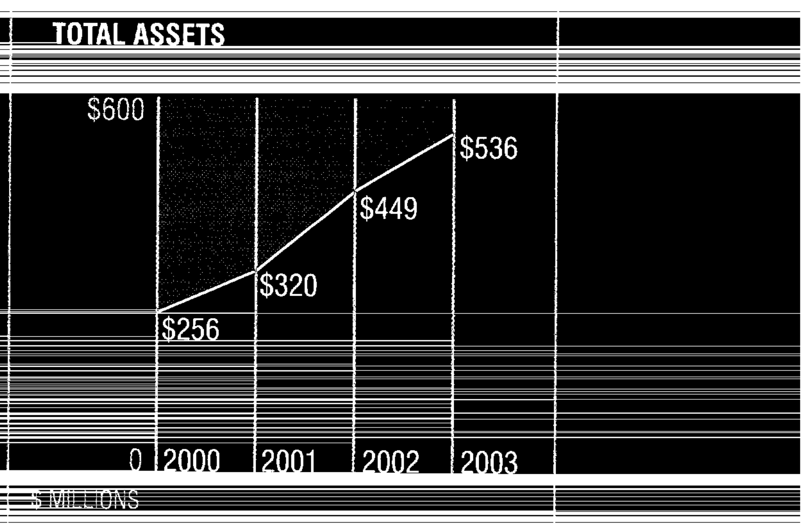
For the year ended December 31, 2003, oil and gas sales were $175.7 million compared to $122.7 million in 2002. Net cash provided by operating activities increased 54% to $96.4 million, and net income was $18.3 million or 138% higher than 2002's net income of $7.7 million. Daily production increased to 102 MMcfe from 96 MMcfe, and total proved reserves rose to 438.8 Bcfe from 412.7 Bcfe. The increase in reserves came primarily through the efficient use of the drill bit and well work as $54.7 million of development and acquisition cost produced a reserve replacement rate of 170% and an all-in finding cost of $0.86 per Mcfe[1]. This reserve replacement rate and FD&A cost was accomplished with development and acquisition costs of only $54.7 million or 40% of the average $135 million of development and acquisition costs in 2000 through 2002. This is a testament to the success of the drilling and other well work conducted in 2003 when capital expenditures for acquisitions were reduced at the request of our former parent company as we prepared for the IPO.

[1] Reconciliations of FD&A and reserve replacement rates are included on page 3.


OIL & GAS REVENUES
$200
$176
$125
$123
$107
0
2000
2001
2002
2003
$ MILLIONS


STOCKHOLDERS' EQUITY
$300
$260
$123
$112
$70
0
2000
2001
2002
2003
$ MILLIONS


CASH FLOW
$100
$96
$62
$63
$42
0
2000
2001
2002
2003
$ MILLIONS


TOTAL ASSETS
$600
$536
$449
$320
$256
0
2000
2001
2002
2003
$ MILLIONS

A PROVEN METHOD FOR GROWTH

Since the inception of our Big Up plan, we have taken our growth targets even more seriously. We expect much of our growth to come from the exploitation and development of our proved and unproved existing properties. We plan to step up our 2004 drilling program, increasing our drilling budget to approximately $68 million from $40 million in 2003. These 2004 drilling plans call for daily production to increase approximately 10%. We also intend to actively pursue acquisitions – something we've done with success since our formation in 1980. We have the financial capacity to add to our existing production base through successful development efforts and additional acquisitions.

We believe our key competitive strengths lie in our diversified asset base, our experienced management team and our commitment to efficient utilization of new technologies. Whiting's future growth is founded on a proven track record of increasing reserves and production through acquisition, exploitation and development. We use acquisitions as a growth vehicle; therefore, our approach to this activity is different from the less active acquirer. We have a great team of managers who know what and where to buy, and how to get more from the assets after the acquisition. With any acquisition, we do not rely on any upward spike in commodity prices to generate our targeted returns. Our process is more involved than that. It includes detailed review of the competitive landscape: reserve size, the acquisition's undeveloped potential and associated risk, the possibility to expand beyond the acquired acreage, cost containment, sales infrastructure, and environmental requirements. We emerge from this meticulous analysis with a total understanding of the properties under appraisal. We expect this total immersion evaluation to deliver 15% to 20% pre-tax returns on our invested acquisition capital. The confluence of talent and experience means that when an acquisition is completed, our managers have comprehensive exploitation and development plans in place to increase the known reserves and daily volumes.

We support our team of veteran oil professionals with state-of-the-art technologies. Whiting's management team averages 26 years of oil field experience. Our acquisition and operations team averages more than 26 years of experience in the evaluation, acquisition and operation of oil and natural gas properties. In each of our core areas we have in-depth geological and geophysical knowledge. We use an inter-disciplinary approach to get the most from our acquired properties, meaning our engineering, land, geologic and financial teams collectively assess the potential of each acquisition before we make an offer to purchase.

COMMITTED TO SHAREHOLDER GROWTH

I am proud to be associated with the entire Whiting team and their many accomplishments and strong work ethic. They join me in welcoming you as shareholders in a dynamic enterprise as we implement our plan to expand our reserve base and increase production. We will continue to use advanced technologies and efficient operations to boost yearly production, while increasing the underlying value of our reserves. We will be vigilant in our analysis and acquisition of operated and non-operated properties, and remain focused on long-term shareholder value.

Sincerely,

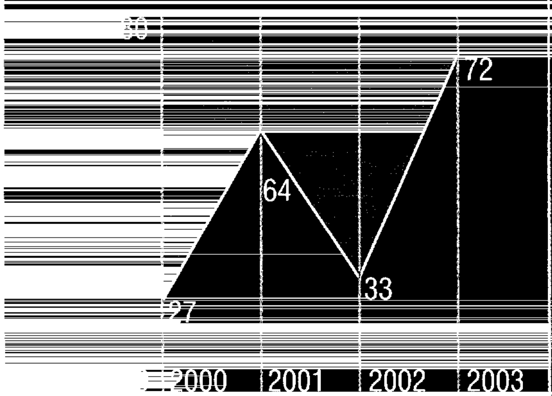
James J. Volker

James J. Volker

President and Chief Executive Officer

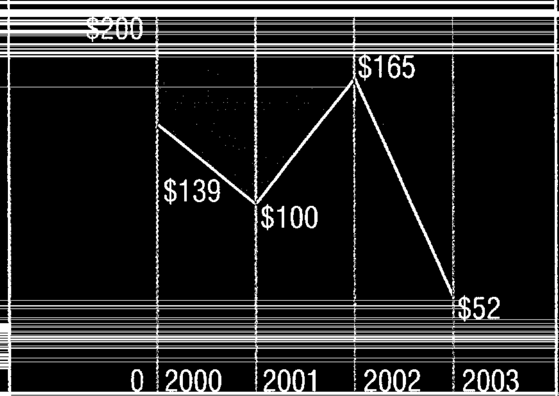
February 25, 2004

DRILLING ACTIVITY



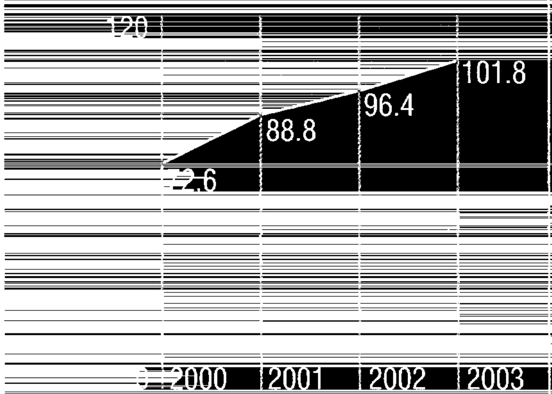
GROSS WELLS DRILLED

TOTAL CAPITAL EXPENDITURES



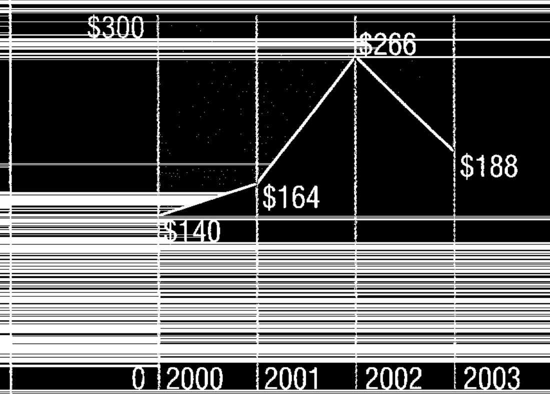
$ MILLIONS

PRODUCTION



Mmcfe/d

LONG-TERM DEBT



$ MILLIONS

DRILLING AND OPERATIONS OVERVIEW

ROCKY MOUNTAINS

At year-end 2003, our proved reserves in the Rocky Mountain region were 29.4 MMBoe which accounted for 40.2% of our total proved reserves. The majority of our interests in the Rocky Mountain region are within North Dakota and Montana, where we have interests in 97 fields, 45 of which we operate. Currently, the Rocky Mountain Division accounts for 31.7% of our daily production and 33.3% of our total net pre-tax SEC PV-10 value.

We have interests in 775 active producing wells, and are currently the 5th largest oil producer in North Dakota. Our goal for the next five years is to substantially increase that acreage position, increase our reserve base, continue to operate most of the wells in which we participate and significantly increase our daily production volumes.

Our operating expertise is evidenced by how we have grown our Williston Basin reserves. At acquisition, the recorded reserves amounted to 136.7 Bcfe. At year-end 2003, we estimate the reserves associated with these properties are 170.1 Bcfe, or 24.5% greater than the original engineering calculations. Our critical mass here offers recurring, low-risk and significant growth opportunities. We are budgeting development spending of $14 million, to drill or recomplete approximately 47 gross wells in the Rocky Mountain region.

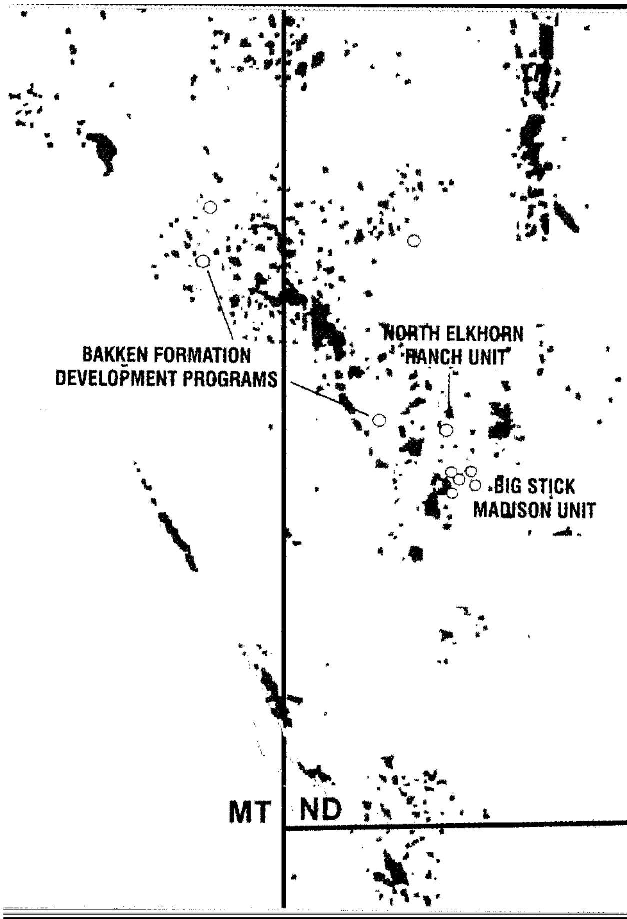
We have many years of development projects in two operating areas in the Williston Basin: Big Stick Madison Unit and North Elkhorn Ranch Unit. These operating areas offer sizeable opportunities in the Bakken, Nisku and Mission Canyon Formations. In addition we have opportunities in the Golden Valley area of western North Dakota.

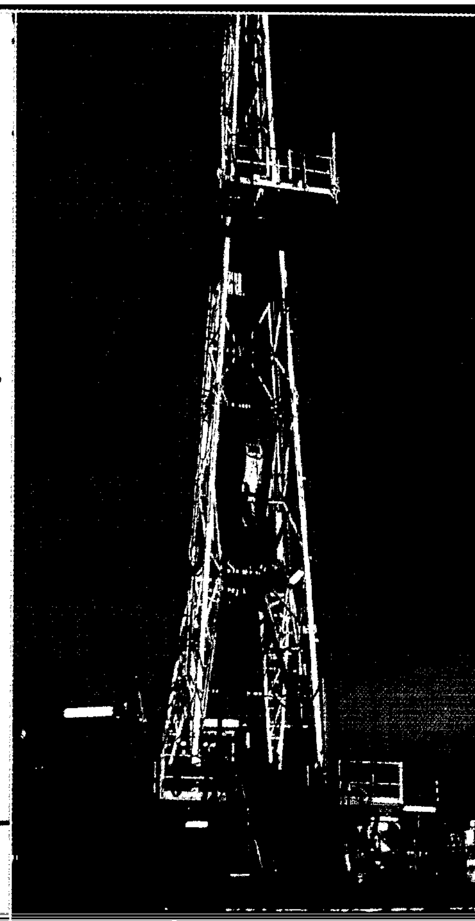
Whiting's largest operated field in the Williston Basin is the Big Stick Field, which contains the Big Stick Madison Unit. We acquired an operated 62% working interest in the field and associated leasehold in early 2002. Production within this field is primarily from a series of stacked, oil-saturated, 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.

The Big Stick Madison Unit contains 37 producing wellbores and 12 water-injection wells. We are developing the unit on 160-acre spacing. Independent engineering estimates indicate that at year-end 2003, our properties in the Big Stick Field contain 12.6 MMBoe of net proved reserves with a net pre-tax SEC PV-10 value of $98.6 million.

We completed a detailed reservoir model study of the Mission Canyon Formation in 2003. Specifically, this study indicates that production to date accounts for only 18% of the estimated 276 MMBbls of oil originally in place within the Mission Canyon horizon. We will drill vertical and horizontal wells to access

Opposite page: drilling operations, Lynne 43-2 Wabek Field, Mountrail County, ND





Gas Fields

Oil Fields

Current Drilling Projects

poorly drained portions of the reservoir, with the expectation of recovering a greater portion of the original oil in place. We believe horizontal wells, drilled as sidetracks from existing vertical wellbores, will optimize our capital investment.

Other formations in Big Stick offer additional opportunities. The Duperow Formation has produced 1.6 MMBbls of oil and 2.3 Bcf of natural gas from three pools within the Big Stick Field. At the time the unit was formed, several Duperow wells were shut-in while still producing more than 100 barrels of oil per day with low water cuts. The Red River Formation tested at a rate of 2.2 MMcf per day of natural gas on a brief production test in 1979. The formation was not produced because of high (9.7%) hydrogen sulfide content and a lack of pipelines or facilities to transport or process this natural gas. Currently there are facilities in the area capable of transporting and processing this natural gas. As proven by our Egly #11-20 well, we believe that the Duperow and the Red River Formations can be economically developed with vertical wells and existing infrastructure. We completed the drilling of the Egly #11-20 well in December of 2003 and tested it at rates over 2,000 Mcf/d.

Just eight miles north of the Big Stick Field, the Whiting-operated North Elkhorn Ranch Unit (60% working interest) 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. Our properties here contain 4.5 MMBoe (94% oil) of net proved reserves (83% developed) with a net pre-tax SEC PV-10 value of $31.3 million.

We are developing North Elkhorn on 160-acre spacing. We have 22 producing wellbores and six water-injection wells. 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. In 2004, we plan to develop an integrated reservoir model study to define the optimal development plan for the North Elkhorn Ranch Unit.

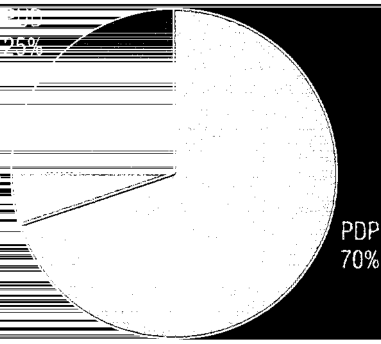
In addition to the projects described above, we are involved in several additional drilling projects on our Williston Basin properties. In Richland County, Montana, we successfully drilled a five-well horizontal drilling program targeting the Middle Bakken Dolomite in the Red Water Field. We have a 40% working interest in this project. These wells are drilled with dual horizontal boreholes and are fracture stimulated to enhance production. The estimated ultimate recovery from the first two wells is 704 MBbl gross (232 MBbl net) per well. We believe the newer fracture technologies that have been instrumental to our success in Richland County have the potential to be applied to our extensive leasehold to the east in Billings, McKenzie and Golden Valley Counties, ND.

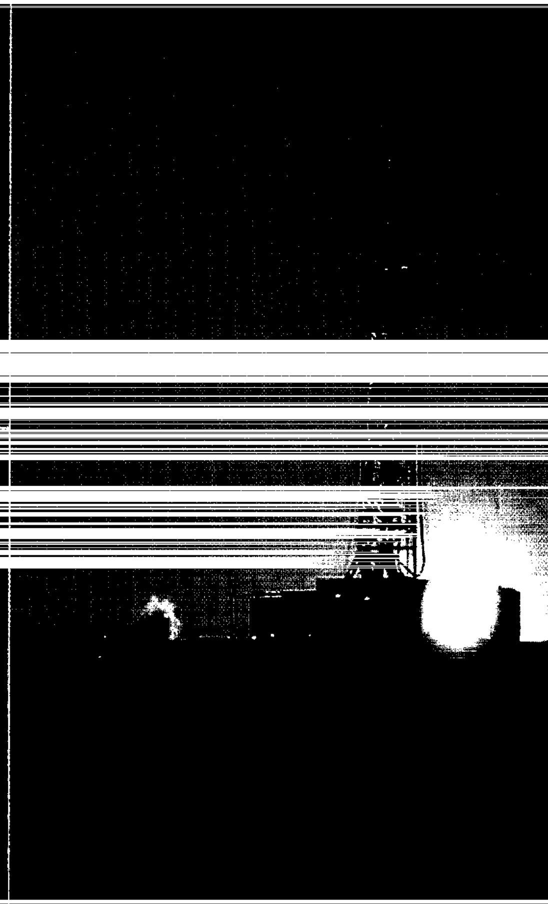
GULF COAST

We acquire properties most often in areas where multiple gas and oil bearing formations are known to exist. Even though this is considered development drilling, we have been successful in increasing the known productive capacity from the acquired properties. Our success is the result of the financial

Opposite page: drilling operations, Wurtz 12-11 Wabek Field, Mountrail County, ND

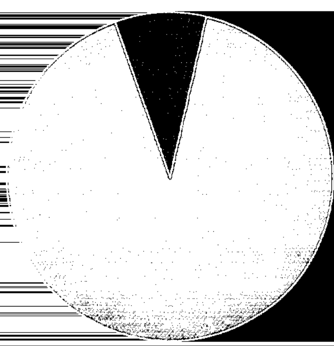
COMPANY-WIDE PROVED RESERVES





6MM SEC PV-10, Year-End 2003

FUTURE DEVELOPMENT, ROCKIES



MM SEC PV-10

discipline and hands-on experience we possess in our core operating regions. We continually find new reserves in areas previously thought to have been fully developed. Such is the case with our Gulf Coast properties.

The Gulf Coast represents Whiting's second largest region, accounting for 27.9% of total proved reserves, or 122.5 Bcfe, in 2,423 wells on 168,117 gross acres, with a net pre-tax SEC PV-10 valuation of $266.7 million. The area produces 40.0 MMcfe per day, or 39% of Whiting's total daily output. During the four years ended 2003, we drilled 88 wells with a 79% success rate. The region, we believe, offers Whiting many multi-pay prospects targeting the Yegua, Edwards, Wilcox, Vicksburg, Frio and Sligo formations. Several of our planned wells in 2004 will be drilled into these formations. We are budgeting development spending of $38 million, to drill or recomplete approximately 56 gross wells in the Gulf Coast area.

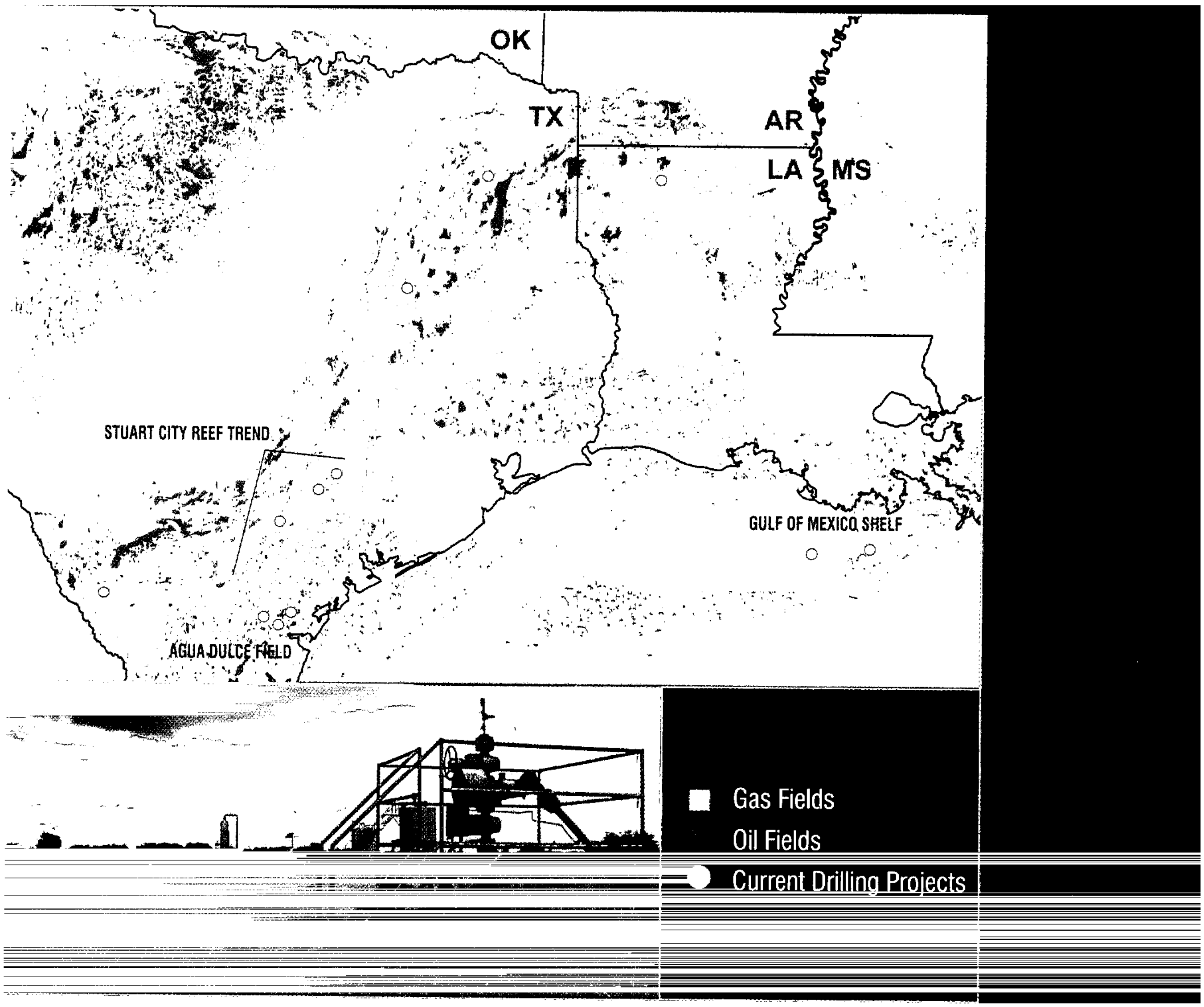
In June 2001, Whiting acquired 26.5 Bcfe of reserves (average 65% working interest) in five fields in the Stuart City Reef Trend: Word North, Yoakum, Kawitt, Sweet Home, and Three Rivers. Whiting's development activities subsequent to the acquisition of these fields caused estimated proved reserves, after production, to increase 34% and now stand at 35.5 Bcfe. In addition to several commonly encountered formations which underlie this prolific hydrocarbon province, production in the Stuart City Reef Trend comes primarily from the Frio, Yegua, Edwards, Wilcox, and Sligo formations at depths between 7,000 and 16,000 feet. Whiting has 22 proved undeveloped drilling locations in its Stuart City inventory. During 2003 we drilled and completed four wells. Results of this drilling combined with higher gas prices have encouraged us to accelerate our program to 17 wells during 2004.

The natural gas column in the Edwards Limestone ranges between 150 and 600 feet thick, but these reservoirs are characterized by extremely low permeability and moderate porosity. Whiting uses horizontal and directional drilling technologies to access up to 3,000 gross feet of Edwards Limestone from a single well to effectively drain the reservoir. These horizontal wells can often be drilled as re-entry wells from existing vertical wellbores, resulting in significant cost savings over drilling new wells. The application of these two techniques has resulted in significantly improved economic parameters for developing our Edwards Limestone natural gas reserves.

The Word North Field (average 35% working interest) is the largest of three contiguous Edwards Limestone natural gas reservoirs located in Lavaca County, TX. Whiting's properties in the Word North Field contain 15.8 Bcfe of net proved reserves with an estimated net pre-tax SEC PV-10 value of $30.0 million.

Whiting's Yoakum Field produces primarily from the Edwards and Wilcox Formations, with productive natural gas flow rates established in the Sligo Formation at 16,000 feet. We operate five wells in the Yoakum Field with an 86% average working interest. Most of our undeveloped locations are in units with an average working interest of 98%. The Yoakum Field contains 10.6 Bcfe of net proved reserves with a net pre-tax SEC PV-10 value of $21.5 million. With 2-D seismic data and well control, we have defined significant remaining development potential in the eastern and southern parts of the field. We re-entered the Julia Mott #1H well in April 2003 and drilled a horizontal lateral from the existing well.

Opposite page: drilling operations, Julia Mott #2 Yoakum Field, DeWitt County, TX


OK
TX
AR
LA
MS
STUART CITY REEF TREND
GULF OF MEXICO SHELF
AGUA DULCE FIELD
Gas Fields
Oil Fields
Current Drilling Projects

After the work, the well produced with an initial rate of 2,500 Mcf per day. We intend to drill six wells in Yoakum Field during 2004.

The Kawitt Field (100% working interest) produces primarily from the Edwards Limestone at 13,400 feet, with secondary production from the Wilcox and Yegua Formations at depths between 6,600 and 9,500 feet. Our proved undeveloped drilling projects at Kawitt Field consist of the three Edwards and four Wilcox wells. In addition, we hold significant undeveloped acreage within the productive area of the Kawitt Field. Drilling in this field is supported with 3-D seismic data, which we use to identify the locations of faults within the reservoir and to estimate reservoir thickness. In September 2003, we drilled the Rhodes Trust #2 well to 9,600 feet. This well's initial production rate was 254 barrels of oil per day from the Wilcox Formation. We re-entered and sidetracked the Waskow #2H well, establishing an initial producing rate of 1,300 Mcf/d from the Edwards Limestone at 15,689 feet. We drilled three horizontal re-entry wells in the Edwards Limestone and one vertical well in the Wilcox Formation in 2003.

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, TX. We have significant ongoing operations in the Agua Dulce Field, where we operate 13 wells with a 99% average working interest. At year-end 2003, our properties in the Agua Dulce Field contained 17.7 Bcfe (90.4% natural gas) of net proved reserves, with a net pre-tax SEC PV-10 value of $60.9 million. We drilled three wells, completing two, in Agua Dulce in 2003. Six wells are scheduled to be drilled in this field in 2004.

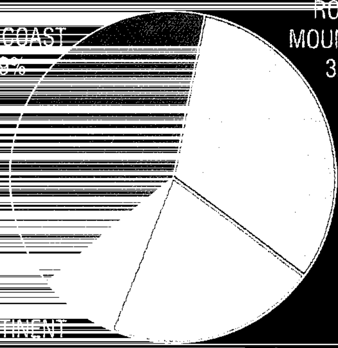
Natural gas and oil production in our Vicksburg Trend is from multiple, low permeability sandstone reservoirs within the Vicksburg and Frio Formations at depths ranging between 4,000 and 15,000 feet. These reservoirs are contained within highly faulted structures, typically resulting in multiple reservoir compartments within a given field. Our use of 3-D seismic data to delineate trapping faults and to directly detect oil and natural gas reservoirs has significantly enhanced our ability to discover and develop these reserves.

Production in the Agua Dulce Field is from a series of highly faulted, over-pressured, low permeability sandstones within the Vicksburg Formation at depths ranging from 8,000 to 10,000 feet. 3-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, which are then fracture stimulated and simultaneously produced.

In the South Olmos Field, we own an average 50% working interest in 250 natural gas wells located in Webb and LaSalle Counties, TX. These wells produce from low permeability sands in the Olmos, Escondido and Wilcox Formations at depths ranging from 4,000 to 8,000 feet. We're using advanced drilling and fracture stimulation technology to reduce our drilling costs and increase our reserve and production volumes. Our net daily production from these non-operated wells is 4,000 Mcf/d. At December 31, 2003, these properties contained 13.7 Bcfe of net proved reserves with a net pre-tax SEC PV-10 value of $24.9 million. Development of these properties has continued at a steady pace with six to 12 new wells drilled per year since 1998. We expect to focus future development activities on the Escondido Formation in the Santo Tomas Field, where a total of four wells were drilled and completed during 2003.

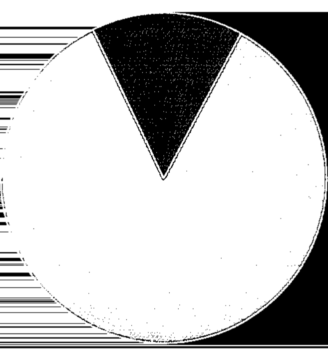
Opposite page: production facilities, Haidusek #1 Holyfield Area, Lavaca County, TX

COMPANY-WIDE AVERAGE DAILY PRODUCTION

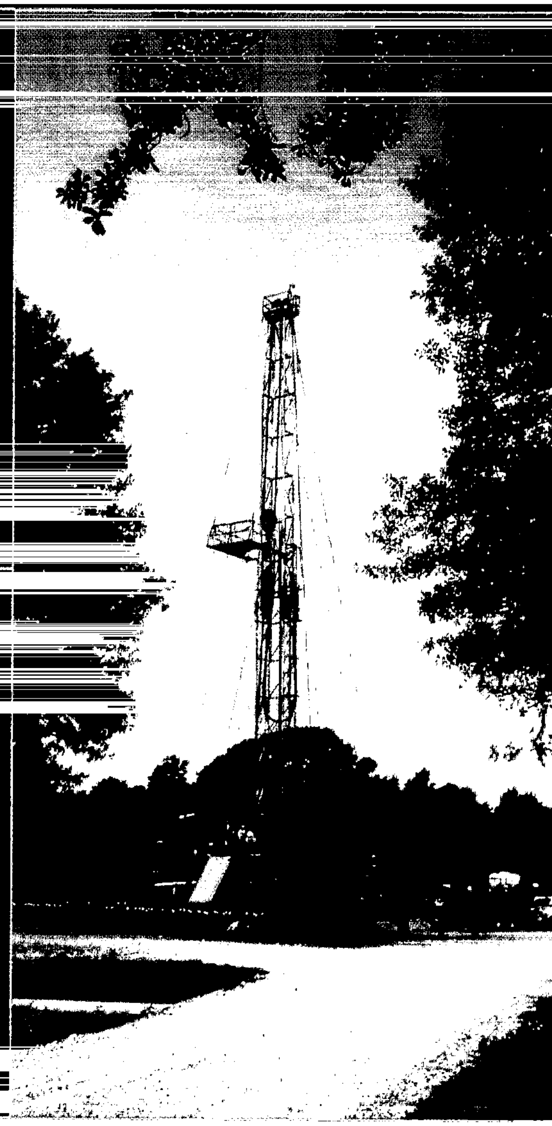


102 MMcfe/d, 2003 Year-End Exit Rate

FUTURE DEVELOPMENT, GULF COAST



[illegible] SEC PV-10



In addition to the projects described above, we have an 18% working interest in a successful, non-operated drilling and recompletion project in South Timbalier Block 185 of the Gulf of Mexico shelf area, offshore Louisiana. We have additional interests in ongoing drilling activity in South Timbalier Blocks 200 and 203.

MICHIGAN

In northern Michigan, we own an interest in 57 multi-well Antrim Shale natural gas projects with proved reserves and additional unproved potential. We participated in the drilling and completion of 15 Antrim Shale wells in 2003. We believe that significant upside potential exists in the West Branch, South Buckeye and Clayton Fields, which produce natural gas from the Glenwood and Prairie du Chien Formations. The Michigan region contributes 114.1 Bcfe (almost entirely natural gas) of net proved reserves to our portfolio of operations, which represents 26.0% of our total net proved reserves. We are budgeting development spending of $10 million, to drill or recomplete approximately 54 gross wells in Michigan.

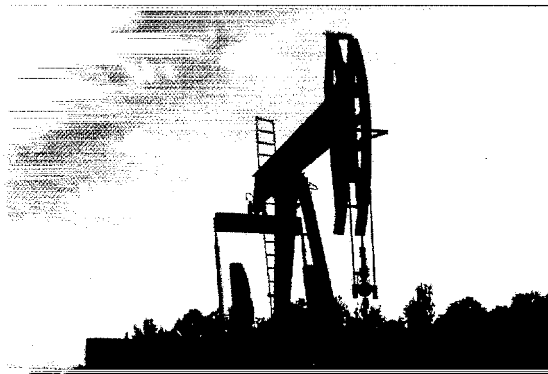
Production in Michigan can be divided into two groups. The majority of the reserves are in non-operated Antrim Shale wells. The remainder of the Michigan reserves are operated and are typified by more conventional oil and gas production located in the central and southern parts of the state. Additionally, we operate the West Branch and Stoney Point natural gas processing plants in the region. We believe these plants to be 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. Our net production from the Antrim Shale (average 39% working interest) natural gas projects is 15.9 MMcf/d.

Approximately 20 of our Antrim Shale projects have significant remaining development potential. In Briley Township, we have proved undeveloped reserves of 5.9 Bcf. The Old Vandy Projects in Charlevoix and Otsego Counties have proved undeveloped reserves of 2.0 Bcfe. An additional 4.9 Bcf of proved undeveloped reserves are present in the remaining projects which are less geographically concentrated. The aggregate net pre-tax SEC PV-10 value of our Antrim Shale development opportunities is $22.1 million. During 2003, we drilled 15 wells. We expect to drill 30 Antrim wells in 2004.

Our non-Antrim Shale production is from conventional reservoirs (primarily the Prairie du Chien, Trenton-Black River Formations) located in central Michigan. Estimated net proved reserves from these properties total 34.5 Bcfe with a net pre-tax SEC PV-10 value of $82.1 million. We operate seven of the 20 oil and natural gas fields in this region where we have an interest. Our conventional non-Antrim Shale fields are producing 5.4 MMcfe/d, net to our interest.

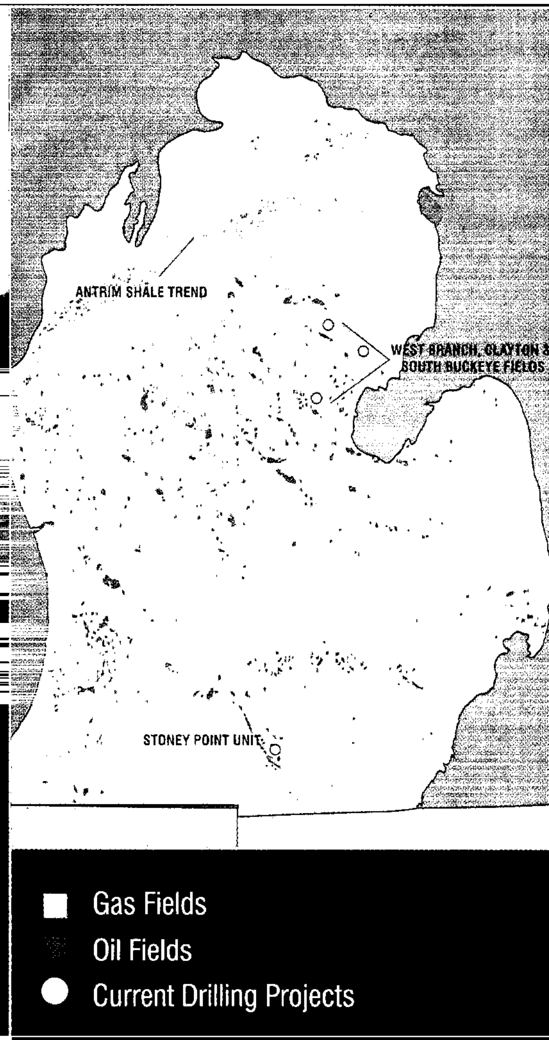
The Prairie du Chien fields produce natural gas and retrograde condensate from various intervals within a 500- to 800-foot thick sequence of sandstones and dolomitic sandstones at a depth of 10,500 to 11,200 feet. The low permeability and heterogeneous character of the Prairie du Chien reservoirs has 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.

Opposite page: drilling operations, Huff 1-32 Springfield Field, Kalkaska County, MI



FUTURE DEVELOPMENT, MICHIGAN

$56.9MM SEC PV-10



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 thirty 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.

Note: each director's election date referred to above represents the first year of Board affiliation with either Whiting Petroleum Corporation or Whiting Oil and Gas Corporation.

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, 2003

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 [ ] No [X]

Aggregate market value of the voting stock held by nonaffiliates of the registrant at June 30, 2003: Not applicable.

Number of shares of the registrant's common stock outstanding at February 15, 2004: 18,750,000 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2004 Annual Meeting of Stockholders are incorporated by reference into Part III.

TABLE OF CONTENTS

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 the pending merger with Equity Oil Company; 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 facility; 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.

DEFINITIONS

Unless the context otherwise requires, the terms "Whiting," "we," "us," "our" or "ours" when used in this Annual Report on Form 10-K refer to Whiting Petroleum Corporation, together with its only operating subsidiary, Whiting Oil and Gas Corporation. When the context requires, we refer to these entities separately. The term "Alliant Energy," when used in this report, refers to Alliant Energy Corporation, our former parent company.

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.

"Boe" Barrels of oil equivalent, determined using the ratio of six thousand cubic feet of natural gas to one barrel of oil.

"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.

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

"MMBoe" One million barrels of oil equivalent.

"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

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Gulf Coast/Permian Basin, Rocky Mountains, Michigan and Mid-Continent regions of the United States. Our focus is on pursuing growth projects that we believe will generate attractive rates of return and maintain 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, 2004, our estimated proved reserves had a pre-tax PV10% value of approximately $784.6 million, approximately 85% of which came from properties located in three states: Texas, North Dakota and Michigan. We spent approximately $52.0 million on capital projects during 2003, including $38.8 million for the drilling of 72 gross (24.8 net) wells (64 successful completions and eight uneconomic wells). We have budgeted approximately $68.0 million for capital expenditures in 2004, including $33.0 million for the development of proved reserves and $35.0 million for the development of currently unproved reserves. Although we have no specific budget for acquisitions, we will also continue to seek property acquisition opportunities that complement our existing core properties. We believe that our exploitation and acquisition expertise and our exploration inventory, together with our operating experience and efficient cost structure, provide us with the potential to continue our growth.

We have a balanced portfolio of oil and natural gas reserves, with approximately 53% of our proved reserves consisting of natural gas and approximately 47% 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 trailing 12 month production ending December 31, 2003 of approximately 11.8 years. Approximately 75% of our proved reserves are classified as proved developed and approximately 25% are classified as proved undeveloped.

The following table summarizes our total net proved reserves and pre-tax PV10% value within our four core areas as of January 1, 2004, as well as our December 2003 average daily production.

	Proved Reserves				December 2003 Average Daily Production	
Core Area	**Oil (MMBbl)**	**Natural Gas (Bcf)**	**Total (Bcfe)**	**Pre-Tax PV 10% Value (In thousands)**	**MMcfe**	**% Natural Gas**
Gulf Coast/Permian Basin	5.5	89.4	122.5	$ 266,745	40.0	76%
Rocky Mountains	26.5	17.6	176.5	261,071	32.3	11%
Michigan	1.1	107.2	114.1	214,407	21.3	92%
Mid-Continent	1.5	16.8	25.7	42,400	8.2	73%
Total	34.6	231.0	438.8	$ 784,623	101.8	59%

Prior to our initial public offering in November 2003, we were a wholly-owned subsidiary of Alliant Energy Corporation, an energy services provider engaged primarily in regulated utility operations in the Midwest, with other non-regulated domestic and international operations.

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. We own interests in a total of 517,000 gross (206,000 net) developed acres. In addition, as of December 31, 2003, we owned interests in approximately 386,000 gross (188,000 net) undeveloped acres that contain many exploitation opportunities. Over the three years ended December 31, 2003, we have invested $94 million to participate in the drilling of 169 gross (60.6 net) wells. The majority of these wells have been developmental wells, and 85.2% were successful completions. As of January 1, 2004, we had identified a total of 171 proved undeveloped drilling locations on our properties. We drilled or participated in the drilling of 72 gross (24.8 net) wells during the year ended December 31, 2003. We plan to invest $68 million on the further development of our properties in 2004.

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 and engineering and geoscience professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties.

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.

Controlling Costs through Efficient Operation of Existing Properties. We operate approximately 60% of the pre-tax PV10% value of our total proved reserves and approximately 82% of the pre-tax PV10% value of our proved undeveloped reserves, which we believe enables us to better manage expenses, capital allocation and the decision-making processes related to our exploitation and exploration activities. For the year ended December 31, 2003, our lease operating expense per Mcfe averaged $1.16 and general and administrative costs averaged $0.34 per Mcfe produced, net of reimbursements.

Competitive Strengths

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

Diversified Asset Base. We have interests in 5,006 wells in 16 states across our four core geographical areas of the United States. 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 26 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 653 square miles of 3-D seismic data, which we have assembled primarily over the past five years. A team with access to state-of-the-art geophysical/geological computer applications and hardware analyzes this information. 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 technology and expertise has greatly aided our pursuit of attractive development projects.

Proved Reserves

Our proved reserves as of January 1, 2004 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)
Gulf Coast/Permian Basin:						
PDP	4,300	52,322	78.1	17.8%	$ 172,347	$ 2,784
PDNP	287	6,232	8.0	1.8%	20,465	1,141
PUD	939	30,856	36.4	8.3%	73,933	25,794
Total Proved:	5,526	89,410	122.5	27.9%	$ 266,745	$ 29,719
Rocky Mountains:						
PDP	18,898	13,183	126.6	28.8%	$ 169,051	$ 743
PDNP	571	205	3.6	0.8%	4,340	393
PUD	7,008	4,257	46.3	10.6%	87,680	18,774
Total Proved:	26,477	17,645	176.5	40.2%	$ 261,071	$ 19,910
Michigan:						
PDP	469	76,263	79.1	18.0%	$ 133,618	$ 0
PDNP	140	6,914	7.8	1.8%	23,854	1,713
PUD	536	24,017	27.2	6.2%	56,935	14,755
Total Proved:	1,145	107,194	114.1	26.0%	$ 214,407	$ 16,468
Mid-Continent:						
PDP	1,438	15,900	24.5	5.6%	$ 41,271	$ 0
PDNP	53	863	1.2	0.3%	1,129	229
Total Proved:	1,491	16,763	25.7	5.9%	$ 42,400	$ 229
Total Corporate:						
PDP	25,105	157,668	308.3	70.2%	$ 516,287	$ 3,527
PDNP	1,051	14,214	20.6	4.7%	49,788	3,476
PUD	8,483	59,130	109.9	25.1%	218,548	59,323
Total Proved:	34,639	231,012	438.8	100%	$ 784,623	$ 66,326

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 2003, 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. Our credit agreement is also secured by a first lien on substantially all of our assets. We do not believe that any of these burdens materially 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 commences, restrict the types, quantities and concentrations of various substances 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 waste 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 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 waste 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 wastes 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 wastes 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 wastes 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 wastes were not under our control. Similarly, the waste disposal facilities where wastes 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. Our properties, adjacent affected properties, the disposal sites, and the waste itself may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed wastes, including wastes 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.

At this time, we do not believe that we are associated with 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 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. Liability under OPA is strict, and under certain circumstances joint and several, and potentially unlimited. 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 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 required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. We believe we are in compliance with all applicable OPA financial responsibility obligations. Any failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. 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 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 applicable 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 wastes 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 for 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 updated SPCC plans beginning in early 2004. 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 updating of our SPCC plans will not have a significant impact on 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, 2003, we had 110 full-time employees, including five senior level geoscientists and fourteen 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

Gulf Coast/Permian Basin Region

Our Gulf Coast/Permian Basin operations include assets in Texas, Louisiana, Alabama and New Mexico. The Gulf Coast/Permian Basin region contributes 122.5 Bcfe (73% natural gas) of net proved reserves to our portfolio of operations, which represents 27.9% of our total net proved reserves. Approximately 90.9% of the proved reserves of our Gulf Coast/Permian Basin operations are related to properties in Texas.

Stuart City Reef Trend. We have leasehold interests in five fields located along a regional geologic structure known as the Stuart City Reef Trend in south-central Texas, where we are employing horizontal drilling technologies to develop gas reserves in the Edwards Limestone at 14,000 feet. Our Stuart City properties contain 35.5 Bcfe of net proved reserves primarily within the Word North field, the Yoakum field and the Kawitt field. During 2003, we drilled three successful Edwards wells in these fields. We plan to continue development of our Edwards gas reserves by drilling a combination of new horizontal wells and casing-exit horizontal wells. We have also begun an active drilling program targeting the Wilcox Formation at 10,000 feet. During 2003, we drilled one Wilcox well and plan additional drilling in the Kawitt and Word North fields.

Vicksburg Trend. We own interests in several fields within the Vicksburg Trend located in the vicinity of Nueces Bay in San Patricio and Nueces Counties, Texas. These fields include the Agua Dulce, Triple A, South Midway, and East White Point fields. Natural gas and oil production in this area is from multiple, low permeability sandstone reservoirs within the Vicksburg and Frio Formations at depths ranging between 4,000 and 15,000 feet.

In the Agua Dulce field, we operate 13 wells with a 99.0% average working interest. Our properties in this field contain 17.7 Bcfe of net proved reserves. We have begun an active development program at Agua Dulce where we are employing 3-D seismic to exploit multiple, low permeability gas sands within a highly faulted anticline. During 2003 we drilled one successful gas well, but had mechanical difficulties in completing a second well and are currently sidetracking the wellbore. We plan to continue the development of our gas reserves through the acquisition of additional seismic data and new drilling.

Gulf of Mexico. In South Timbalier Block 185, we have an 18% working interest in a successful, non-operated drilling and recompletion project in of the Gulf of Mexico shelf area, offshore Louisiana. We also have interests in ongoing drilling activity in South Timbalier, Blocks 185, 200 and 203, which we expect to continue during 2004.

Cotton Valley Reef Trend. We are involved in an exploration play along the Cotton Valley Reef trend primarily in Leon and Robertson counties, Texas. Fields along this trend produce gas from pinnacle reefs within the Cotton Valley formation at 14,000 feet. We are employing modern seismic processing techniques to accurately delineate these reservoirs. We are currently drilling one of these wells and plan one additional well in 2004.

Rocky Mountain Region

Our Rocky Mountain operations include assets in North Dakota, Montana, Colorado and Wyoming. As of January 1, 2004, our proved reserves in the Rocky Mountain region were 29.4 MMBoe (90% oil), which accounted for 40.2% of our total proved reserves. The majority of our interests in the Rocky Mountain region are within North Dakota and Montana, where we have interests in 97 fields, 45 of which we operate. Approximately 87% of the proved reserves of our Rocky Mountain operations are related to assets in North Dakota.

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. Our net recoverable reserves at Big Stick at year end were 12.6 MMBoe. Since acquiring this property, we have increased unit oil production by 14% through a combination of workovers and sidetracks of existing wells as well as new drilling. During the past year, we have been engaged in a detailed reservoir modeling study to determine the benefits and feasibility of implementing a waterflood within the unit. We are also developing our deeper, non-unitized interests at Big Stick, and recently drilled a new well which identified gas pay in the Red River Formation at 12,700 feet and oil pay in the Duperow Formation at 11,000 feet.

North Elkhorn Ranch Unit. The North Elkhorn Ranch Unit is located eight miles north of the Big Stick field in Billings County, North Dakota and also produces from reservoirs within the Mission Canyon Formation. We hold a 60% working interest and operate this unit. Our net recoverable reserves are 4.5 MMBoe. Since assuming unit operations in May of 2002, we have reversed the decline in unit production, primarily through workovers of existing wells and reduction in downtime. We drilled one unit well late in 2003 and plan additional development drilling during 2004.

Red Water Field. We have a 40% non-operated working interest in an active exploration and development play which targets the middle member of the Mississippian Bakken Formation in Richland County, Montana. During 2003 we drilled four new horizontal wells which have estimated ultimate recoveries of 500 to 800 MBoe per well. At year end, our net recoverable reserves from the Red Water Field were 1.2 MMBoe.

Sioux Field. We have a 65% working interest and operate this field which is located in McKenzie County, North Dakota. This field produces oil and gas from multiple zones at depths up to 13,700 feet. Since acquiring this property in 2002, we have increased production by 130% primarily through new drilling and recompletions. In 2003, we drilled a successful well with up to eight producing zones. Initially, production will be from the Interlake Formation which has tested oil at approximately 250 barrels of oil per day.

Michigan Region

Our Michigan operations include assets in Michigan and Ohio. Virtually all of the proved reserves and pre-tax PV10% value associated with our Michigan operations are from properties located in the State of Michigan. The Michigan region contributes 114.1 Bcfe (94% natural gas) of net proved reserves to our portfolio of operations, which represents 26% of our total net proved reserves.

The majority of our Michigan production is from a non-conventional natural gas reservoir in the northern Michigan basin known as the Antrim Shale. The remainder of our production is from a variety of conventional oil and natural gas reservoirs in the eastern and southern portions of the basin. We operate the majority of our non-Antrim production as well as the West Branch and Stoney Point natural gas plants, while the majority of our Antrim production is operated by local companies in close cooperation with our technical staff.

Antrim Production. Natural gas is produced from fractures within the Antrim Shale at depths from 1,200 to 2,200 feet. The productive fairway of the Antrim is widespread across northern Michigan, covering a 3,400 square mile region. We own interests in 57 multi-well Antrim Shale natural gas projects within this area. As of January 1, 2004, our net proved reserves from these projects were 79.6 Bcfe (100% natural gas).

Approximately 10 of our Antrim Shale projects have significant remaining development potential. These projects are concentrated in three areas. In Briley Township, we have proved undeveloped reserves of 5.9 Bcf. The Old Vandy Projects in Charlevoix and Otsego Counties have proved undeveloped reserves of 2.0 Bcf. An additional 4.9 Bcf of proved undeveloped reserves are present within eight additional townships which are less geographically concentrated. During 2003, we drilled 15 wells, and we expect to drill 20 wells during 2004.

Conventional (non-Antrim) Production. Our non-Antrim Shale production is from conventional reservoirs (primarily the Prairie du Chien, Trenton and Black River Formations) located in Central Michigan. Estimated net proved reserves from these properties total 34.5 Bcfe (80% natural gas). We have interests in 20 oil and natural gas fields in this region and operate 7 of them.

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.

Our undeveloped potential resides in three fields, West Branch, Clayton and South Buckeye. All are structurally trapped hydrocarbon accumulations and to date recoveries range from 4% to 37% of the in place hydrocarbons. Our undeveloped proved reserve potential in these three fields is estimated at 14.4 Bcfe versus 60 Bcfe produced to date. Two locations have been identified for drilling in 2004. We believe that significant additional potential exists for horizontal re-entry wells and conventional vertical and horizontal wells.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. The Mid-Continent region contributes 25.7 Bcfe (65% natural gas) of net proved reserves to our portfolio of operations, which represents 5.9% 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.

Cherokee Basin Coalbed Methane Project. In 2002 and 2003, we acquired a 91,284 acre lease position in the Cherokee Basin, which is prospective for natural gas from coal seams (coalbed methane). Approximately 70,000 acres are concentrated in our Center prospect, which is located south of Emporia, Kansas and in which we have a 100% working interest. Eight stratigraphic test wells were drilled during 2003 and evaluation efforts are ongoing.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2003 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**
Gulf Coast/Permian Basin	159,603	58,813	8,514	7,518	168,117	66,331
Rocky Mountains	137,038	66,507	286,000	90,400	423,038	156,907
Michigan	179,141	59,000	—	—	179,141	59,000
Mid-Continent	40,740	21,438	91,284	90,395	132,024	111,833
Total	516,522	205,758	385,798	188,313	902,320	394,071

Production History

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

	Year Ended December 31,		
	2003	**2002**	**2001**
Oil production (MMBbls)	2.6	2.3	2.1
Natural gas production (Bcf)	21.6	21.4	19.8
Total production (Bcfe)	37.2	35.2	32.4
Daily production (MMcfe/d)	101.8	96.4	88.8
Average sales prices:			
Natural gas (per Mcf)(1)	$ 4.78	$ 3.21	$ 3.82
Oil (per Bbl)(1)	$ 27.50	$ 23.35	$ 23.85
Total (per Mcfe)(1)	$ 4.73	$ 3.48	$ 3.88
Costs and expenses (per Mcfe):			
Lease operating expenses	$ 1.16	$ 0.93	$ 0.92
Production taxes	$ 0.29	$ 0.21	$ 0.20
Depreciation, depletion and amortization expense	$ 1.11	$ 1.24	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.34	$ 0.34	$ 0.34

(1) Before consideration of hedging transactions.

Productive Wells

The following table presents our ownership at December 31, 2003 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	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gulf Coast/Permian Basin	1,571	139.7	852	282.0	2,423	421.7
Rocky Mountains	863	254.7	115	17.9	978	272.6
Michigan	78	57.0	968	368.3	1,046	425.3
Mid-Continent	372	151.2	187	78.8	559	230.0
Total	2,884	602.6	2,122	747.0	5,006	1,349.6

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.*

	Gulf Coast/Permian Basin			Mid-Continent			Rocky Mountains			Michigan		Total		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2003**	**2002**	**2001**
Gross:														
Productive	22	10	22	2	3	3	25	7	31	15	4	64	24	56
Dry	3	6	6	--	--	--	5	3	2	--	--	8	9	8
Total	25	16	28	2	3	3	30	10	33	15	4	72	33	64
Net:														
Productive	10.6	4.2	10.5	0.1	0.2	1.0	7.4	2.7	8.1	2.8	1.0	20.9	8.1	19.6
Dry	.9	2.2	1.9	--	--	--	3.0	2.1	1.9	--	--	3.9	4.3	3.8
Total	11.5	6.4	12.4	0.1	0.2	1.0	10.4	4.8	10.0	2.8	1.0	24.8	12.4	23.4

Our drilling activity from exploratory wells, which are included in the above table, include one productive gross well (0.2 net) in 2001 in the Gulf Coast/Permian Basin region, one dry gross well (0.15 net) in 2002 in the Gulf Coast/ Permian Basin region, three dry gross wells (1.55 net) in 2003, two of which were located in the Rocky Mountain region and one in the Gulf Coast/Permian Basin region.

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

(a) A special meeting of the sole stockholder of Whiting Petroleum Corporation was held on November 25, 2003, immediately prior to the initial public offering of Whiting Petroleum Corporation's common stock. At the time of the special meeting, Alliant Energy Resources, Inc. ("Resources") was the sole stockholder of Whiting Petroleum Corporation.

(b) Not Applicable.

(c) The following matters brought for vote at the Special Meeting passed by the vote indicated:

	Shares Voted			
	For	**Against**	**Withheld**	**Broker Non-Vote**
1. Approval of the Whiting Petroleum Corporation 2003 Equity Incentive Plan	18,330,000	0	0	0
2. Approval of the Whiting Oil and Gas Corporation Phantom Equity Plan	18,330,000	0	0	0

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 15, 2004, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	57	Chairman, President and Chief Executive Officer
D. Sherwin Artus	66	Senior Vice President
James R. Casperson	56	Chief Financial Officer
James T. Brown	51	Vice President, Operations
John R. Hazlett	64	Vice President, Acquisitions and Land
Mark R. Williams	47	Vice President, Exploration and Development
Patricia J. Miller	66	Vice President of Human Resources and Corporate Secretary
Michael J. Stevens	38	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 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-five years of financial and operational experience in the oil and natural gas industry. Mr. Casperson holds a Bachelor's Degree from Texas Tech University.

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 twenty-nine 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.

John R. Hazlett joined us in January 1994 as Vice President of Land and Acquisitions. He has forty years of experience in the oil and natural gas industry as a land man and acquisitions team leader. Mr. Hazlett is a graduate of Ft. Hays State College in Hays, Kansas. Mr. Hazlett is a Certified Professional Landman.

Mark R. Williams joined us in December 1983 as Exploration Geologist, becoming Vice President of Exploration and Development in December 1999. He has twenty-two 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.

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. Mrs. Miller attended business school at Otero Junior College in LaJunta, Colorado and at Texas A & I in Kingsville, Texas.

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.

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 and Related Stockholder Matters

Whiting Petroleum Corporation's common stock is traded on the New York Stock Exchange under the symbol "WLL." The following table sets forth the range of high and low closing sales prices for our common stock for the period from November 20, 2003 (the first day of trading of the common stock on the New York Stock Exchange) through December 31, 2003. Prior to November 20, 2003, no public market existed for our common stock.

	High	Low
Fourth quarter (November 20, 2003 through December 31, 2003)	$18.54	$16.15

On February 15, 2004, there were nine stockholders of record and approximately 6,500 beneficial owners of our common stock.

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, our credit facility prohibits us from paying dividends.

Item 6. Selected Financial Data

The consolidated income statement information for the years ended December 31, 2003, 2002 and 2001 and the balance sheet information at December 31, 2003 and 2002 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 years ended December 31, 2000 and 1999 and the balance sheet information at December 31, 2000 and 1999 are derived from our unaudited financial statements, which are not included in this report. The balance sheet information at December 31, 2001 is derived from audited financial statements that are not included in this report.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
(dollars in millions except per share data)					
Consolidated Income Statement Information:					
Revenues:					
Oil and gas sales	$ 175.7	$ 122.7	$ 125.2	$ 107.0	$ 60.9
Gain (loss) on oil and gas hedging activities	(8.7)	(3.2)	2.3	(3.8)	—
Gain on sale of oil and gas properties	—	1.0	11.7	7.7	10.1
Interest income and other	0.3	—	0.2	0.1	0.1
Total revenues	$ 167.3	$ 120.5	$ 139.4	$ 111.0	$ 71.1
Costs and expenses:					
Lease operating	$ 43.2	$ 32.9	$ 29.8	$ 23.8	$ 20.7
Production taxes	10.7	7.4	6.5	5.4	3.0
Depreciation, depletion and amortization	41.2	43.6	26.9	21.5	19.8
Impairment of proven oil and gas properties	—	—	—	—	3.3
Exploration	3.2	1.8	0.8	1.1	1.9
Phantom equity plan	10.9	—	—	—	—
General and administrative	12.8	12.0	10.9	6.3	4.3
Interest expense	9.2	10.9	10.2	7.5	5.4
Total costs and expenses	$ 131.2	$ 108.6	$ 85.1	$ 65.0	$ 58.4
Income before income taxes and cumulative change	$ 36.1	$ 11.9	$ 54.3	$ 45.4	$ 12.7
Income tax expense	13.9	4.2	13.1	11.7	1.8
Income from continuing operations	22.2	7.7	41.2	33.7	10.9
Cumulative change in accounting principle	3.9	—	—	—	—
Net income	$ 18.3	$ 7.7	$ 41.2	$ 33.7	$ 10.9
Basic and diluted net income per common share from continuing operations	$ 1.18	$ 0.41	$ 2.20	$ 1.80	$ 0.58
Basic and diluted net income per common share	$ 0.98	$ 0.41	$ 2.20	$ 1.80	$ 0.58
Other Financial Information:					
Net cash provided by operating activities	$ 96.4	$ 62.6	$ 62.3	$ 42.3	$ 38.7
Capital expenditures	$ 52.0	$ 165.4	$ 99.6	$ 139.1	$ 34.9

	As of December 31,				
	2003	2002	2001	2000	1999
(dollars in millions except per share data)					
Balance Sheet Information:					
Total assets	$ 536.3	$ 448.5	$ 319.8	$ 256.4	$ 148.5
Long-term debt	$ 188.0	$ 265.5	$ 163.6	$ 139.7	$ 72.5
Stockholder's equity	$ 259.6	$ 122.8	$ 111.5	$ 70.0	$ 36.2

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

Overview

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Gulf Coast/Permian Basin, Rocky Mountains, Michigan and Mid-Continent 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 management is 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.

Results of Operations

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

	Years Ended December		
	2003	**2002**	**2001**
Net production:			
Natural gas (Bcf)	21.6	21.4	19.8
Oil (MMBbls)	2.6	2.3	2.1
Net sales (in millions):			
Natural gas(1)	$ 104.4	$ 68.6	$ 75.4
Oil(1)	$ 71.3	$ 54.1	$ 49.8
Average sales price:			
Natural gas (per Mcf)(1)	$ 4.78	$ 3.21	$ 3.82
Oil (per Bbl)(1)	$ 27.50	$ 23.35	$ 23.85
Costs and expenses (per Mcfe):			
Lease operating expenses	$ 1.16	$ 0.93	$ 0.92
Production taxes	$ 0.29	$ 0.21	$ 0.20
Depreciation, depletion and amortization expense	$ 1.11	$ 1.24	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.34	$ 0.34	$ 0.34

(1) Before consideration of hedging transactions.

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 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. Depreciation, depletion and amortization 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 depreciation, depletion and amortization 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. The liability is discounted using a credit-adjusted risk-free rate of approximately 7%. 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.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Oil and Natural Gas Sales. Oil and natural gas sales revenue decreased approximately $2.6 million to $122.7 million in 2002. Natural gas sales decreased $6.8 million, while oil sales increased $4.2 million. The natural gas sales decrease was caused by a 16% decline in the average realized natural gas price from $3.82 Mcf in 2001 to $3.21 Mcf in 2002, partially offset by an increase in natural gas production of 1.6 Bcf in 2002. The oil sales increase was caused by a sales volume increase of 200,000 Bbls in 2002, partially offset by a 2% decline in the average realized oil price from $23.85 in 2001 to $23.35 in 2002. The volume increase for oil and natural gas was due to $265 million of capital expenditures during 2001 and 2002.

Loss on Oil and Natural Gas Hedging Activities. We hedged 8% of our natural gas volumes during 2002, incurring a hedging loss of $0.2 million, and 11% of our natural gas volumes during 2001, incurring a gain of $1.6 million. We hedged 35% of our oil volumes during 2002, incurring a hedging loss of $3.0 million, and 17% of our oil volumes during 2001, incurring a gain of $0.7 million.

Gain on Sale of Oil and Natural Gas Properties. In 2002, we divested only one property, realizing a gain of $1.0 million, while in 2001, we divested several properties, realizing total sales gains of $11.7 million.

Lease Operating Expenses. Our lease operating expenses per Mcfe increased from $0.92 in 2001 to $0.93 in 2002. 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.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 6.0% in 2002 and 5.2% in 2001. The 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. Depreciation, depletion and amortization expense in 2001 included a $9.0 million reduction related to the abandonment liability for the Point Arguello platform located offshore from California. During 2001, we received a revised and more detailed dismantlement plan from the operator. The $9.0 million reduction of liability was credited against depreciation, depletion and amortization expense since the liability was initially created by charges to depreciation, depletion and amortization expense. Without this credit, our depreciation, depletion and amortization expense charge for 2001 would have been $35.9 million. The increase to $43.6 million of depreciation, depletion and amortization expense in 2002 was a result of increasing sales volumes and an increased rate from $1.11 per Mcfe in 2001 to $1.24 per Mcfe in 2002.

Exploration Costs. Exploration costs increased $1.0 million to $1.8 million for 2002 compared with $0.8 million for 2001. The increase was partially the result of a $420,000 charge for an exploratory dry hole in 2002. The remaining increase in 2002 is related to the further development and processing of our geophysical library.

General and Administrative Expenses. General and administrative expenses increased 9.5% or $1.1 million from $10.9 million in 2001 to $12.0 million in 2002. This increase was related to increases in compensation expense associated with increased personnel required to administer our growth and to general cost inflation.

Interest Expense. Interest expense increased $0.7 million to $10.9 million in 2002 compared to $10.2 million in 2001. The increase was due to higher average debt levels in 2002 to fund our growth, partially offset by a lower effective interest rate.

Income Tax Expense. Our effective tax rate before tax credits was 36.8% in 2002 and 36.2% in 2001. In 2001, we were able to reduce our tax expense by $6.6 million due to the recording of Section 29 tax credits. In 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.

Net Income. Net income decreased from $41.2 million in 2001 to $7.7 million in 2002. The primary reasons were a $19.0 million decline in revenues, a $23.5 million increase in expenses and the inability to recognize $5.4 million of tax credits as a reduction of tax expense. The revenue decrease was caused by a decline in oil and natural gas prices between years and $10.7 million less gains from the sales of properties in 2002. The expense increase was caused by the $9.0 million reduction to 2001 depreciation, depletion and amortization related to the adjustment of the Point Arguello abandonment liability and cost increases in all other categories to operate and administer the property acquisitions during 2001 and 2002.

Liquidity and Capital Resources

Cash Flows. During the year ended December 31, 2003, we generated $96.4 million from operating activities and received $4.6 million in contributions from Alliant Energy. We used a portion of these cash proceeds to fund $52.0 million of capital expenditures. At December 31, 2003, we had $53.6 million of cash on hand and $51.3 million of working capital compared to December 31, 2002 when our cash position was $4.8 million and working capital was $19.4 million.

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 is $68.0 million during 2004. 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 development expenditures from internally generated cash flow during 2004. We believe that should attractive acquisition opportunities arise or development expenditures exceed $68.0 million, we could finance the additional capital expenditures with cash on hand, operating cash flow, additional borrowings under our credit facility, issuances of additional equity or development with industry partners. The 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 Facility. Whiting Oil and Gas Corporation has a $350.0 million credit agreement with a syndicate of banks. At December 31, 2003, the credit agreement provided a borrowing base of $210.0 million with an outstanding principal balance of $185.0 million. On February 17, 2004, we repaid $40.0 million of the outstanding principal balance from cash on hand in excess of projected drilling and production needs. The borrowing base under the credit agreement is based on the collateral value of our proved reserves and is subject to redetermination on May 1 and November 1 of each year. If the borrowing base is determined to be lower than the outstanding principal balance then drawn, we must immediately pay the difference. The credit agreement provides for interest only payments until December 20, 2005, when the entire amount borrowed is due. 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 0.25% to 1.0% depending on the ratio of the amounts borrowed to the borrowing base, or (2) at the LIBOR rate plus a margin where the margin varies from 1.5% to 2.25% depending on the ratio of the amounts borrowed to the borrowing base. At December 31, 2003, all amounts outstanding under the credit agreement bore interest at an annual rate of 3.21% through February 6, 2004. On February 6, 2004, we fixed the rate on the outstanding principal balance at an annual rate of 3.2% through August 6, 2004. The credit agreement has covenants that restrict the payment of cash dividends, borrowings, sale of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders and requires us to maintain certain debt to EBITDAX (as defined in our credit agreement) ratios and a working capital ratio. The credit agreement also precludes us from providing any cash to Alliant Energy except for services rendered on an arm's-length basis or for income taxes. We were in compliance with our covenants under the credit agreement as of December 31, 2003. The credit agreement is secured by a first lien on substantially all of Whiting Oil and Gas Corporation's assets. Whiting Petroleum Corporation has agreed to guarantee the obligations of Whiting Oil and Gas Corporation under the credit agreement.

As part of an overall review of our liquidity and financial condition, we are currently considering refinancing all or a portion of the outstanding debt under our credit agreement through the issuance of senior subordinated debt securities with long term maturities. In addition, if our acquisition of Equity Oil Company closes, then we intend to assume Equity Oil's outstanding debt under its credit facility, which was $29.0 million as of December 31, 2003. See "- Subsequent Event." We will be required to amend our credit agreement to permit this assumption of debt.

Historical Financing. Prior to our initial public offering in November 2003, we functioned as an indirect wholly-owned subsidiary of Alliant Energy. As a result, our liquidity was directly related to the financial resources and capital expenditure allocations of Alliant Energy. In the past, Alliant Energy provided a capital expenditure budget and funded net cash requirements beyond cash generated from operations. Until our $185.0 million bank borrowing in December 2002 as described above, we did not rely on outside sources of borrowing or capital. Instead, we received advances on Alliant Energy's intercompany credit facility, which primarily covered the shortfall between our capital expenditures (including acquisitions) and cash generated from operations and property sales. The table below describes net borrowings and payments on Alliant Energy's intercompany credit facility.

	Year Ended December 31,			
	2003	**2002**	**2001**	**Total**
Alliant Energy(1)	$ (80.9)	$ (83.1)	$ 23.9	$ (140.1)
Whiting credit facility	—	185.0	—	185.0
Total	$ (80.9)	$ 101.9	$ 23.9	$ 44.9

(1) In March 2003, Alliant Energy converted its remaining loan plus accrued interest of $80.9 million to "paid in capital" of Whiting.

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.

Alliant Energy Promissory Note. In conjunction with our initial public offering in November 2003, we 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.

Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of December 31, 2003 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods.

	Payments due by period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-Term Debt	$ 188.0	--	$ 188.0	--	--
Operating Leases	2.0	$ 1.1	0.9	--	--
Tax Separation and Indemnification Agreement with Alliant Energy(1)	28.8	--	4.2	$ 3.1	$ 21.5
Total	$ 218.8	$ 1.1	$ 193.1	$ 3.1	$21.5

(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, 2004 increased to 50% of the actual price received in excess of $19.77 per barrel. Currently, approximately 46,000 net barrels of crude oil per month (21% of December 2003 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. As of December 31, 2003, we have paid $3.1 million under this agreement and we have accrued an additional $215,000 as currently payable.

New Accounting Policies

In June 2001, the Financial Accounting Standards Board, or the FASB, issued Statement of Financial Accounting Standards, or SFAS, No. 141, "Business Combinations," which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite-lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. We did not change or reclassify the contractual mineral rights included in our oil and natural gas properties on the balance sheet upon adoption of SFAS No. 142. We believe that the current accounting of such mineral rights as part of crude oil and natural gas properties is appropriate under the successful efforts method of accounting. However, there is an alternative view that reclassification of mineral rights to an intangible asset may be necessary. If a reclassification of contractual mineral rights acquired subsequent to July 1, 2001 from oil and gas properties to long term intangible assets is required, then the reclassified amounts would be approximately $48.7 million as of December 31, 2001, $161.2 million as of December 31, 2002 and $160.1 million as of December 31, 2003. We do not believe that the ultimate outcome of this issue will have a significant impact on our cash flows, results of operations or financial condition.

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 that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 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. In regards to us, this statement applies directly to the plug and abandonment liabilities associated with our 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. The liability is discounted using a credit-adjusted risk-free rate of approximately 7%. 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, 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). We have an additional $4.3 million abandonment liability relating to our retained obligation with respect to the Point Arguello facility located offshore from California.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associates with Exit or Disposal Activities." This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of this Statement had no impact on our financial statements.

FASB Interpretation No. 45, or FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" was issued in November 2002 by the FASB. FIN 45 requires a guarantor to recognize a liability for the fair value of the obligation it assumes under certain guarantees. Additionally, FIN 45 requires a guarantor to disclose certain aspects of each guarantee, or each group of similar guarantees, including the nature of the guarantee, the maximum exposure under the guarantee, the current carrying amount of any liability for the guarantee, and any recourse provisions allowing the guarantor to recover from third parties any amounts paid under the guarantee. The disclosure provisions of FIN 45 are effective for financial statements for both interim and annual periods ending after December 15, 2002. The fair value measurement provisions of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The adoption of this statement did not have a material impact on our financial statements.

In January 2003, the FASB issued FASB Interpretation No. 46, or FIN 46 (as revised in December 2003), "Consolidation of Variable Interest Entities." FIN 46 clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements" to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated support from other parties. FIN 46 requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. All companies with interests in variable interest entities created after January 31, 2003, shall apply the provisions of FIN 46 to those entities immediately. The adoption of this Statement had no impact on our financial statements.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" to amend and clarify financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. The changes in this statement require that contracts with comparable characteristics be accounted for similarly to achieve more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and will be applied prospectively. The adoption of this Statement had no impact on our financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" to classify certain financial instruments as liabilities in statements of financial position. The financial instruments are mandatorily redeemable shares, which the issuing company is obligated to buy back in exchange for cash or other assets, put options and forward purchase contracts, instruments that do or may require the issuer to buy back some of its shares in exchange for cash or other assets, and obligations that can be settled with shares, the monetary value of which is fixed, tied solely or predominantly to a variable such as a market index, or varies inversely with the value of the issuers' shares. Most of the guidance in SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The adoption of this Statement had no impact on our 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 "Gain (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. 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 and impairment of our oil and natural gas properties. 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 Whiting Oil and Gas Corporation's engineering staff. The independent petroleum engineers evaluated approximately 83% of the pre-tax PV10% value of our proved reserves and Whiting Oil and Gas Corporation's 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. We have not recorded any property impairments since 1999.

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 2001, 2002 and 2003 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.

Subsequent Event

On February 2, 2004, we announced that we entered into a definitive merger agreement to acquire Equity Oil Company. The merger agreement provides for a stock-for-stock merger under which Equity shareholders will receive a fixed exchange ratio of 0.185 shares of our common stock for each share of Equity common stock that they own. In addition, we will assume approximately $29 million of Equity debt. The merger is subject to the approval of shareholders owning two-thirds of the outstanding Equity shares and other customary closing conditions. Equity intends to call a special meeting of its shareholders during the second quarter of 2004 to consider and vote on the merger. We expect to complete the merger as soon as practicable following approval by Equity's shareholders.

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 December 2003 production, our income before income taxes moves approximately $2.1 million for every $0.10 change in natural gas prices and approximately $2.4 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 generally limit our aggregate hedge position to less than 50% of expected production, but may hedge larger percentages of total expected production in certain circumstances. We do not intend to hedge in excess of 60% of our expected production. We also seek to diversify our hedge position with various counterparties where we have clear indications of their current financial strength.

Our hedging arrangements have the effect of locking in for specified periods the prices we will receive for the volumes and commodity to which the hedge relates. 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. For the natural gas contracts listed below, 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 $255,000 in 2004. For the crude oil contracts listed below, a hypothetical $1.00 change in the NYMEX price would cause a change in the gain (loss) on hedging activities of $450,000 in 2004.

Our outstanding hedges at February 1, 2004 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)	NYMEX Floor/Ceiling
Natural Gas	01/2004 to 03/2004	300,000	$ 4.50/7.00
Natural Gas	01/2004 to 03/2004	250,000	$ 4.50/8.45
Natural Gas	01/2004 to 03/2004	300,000	$ 4.50/8.05
Crude Oil	01/2004 to 03/2004	50,000	$ 28.00/31.43
Crude Oil	01/2004 to 03/2004	50,000	$ 28.00/32.10
Crude Oil	04/2004 to 06/2004	50,000	$ 28.00/35.40

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 December 31, 2003 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	2004 Price Per MMBtu
Natural Gas	01/2002 to 12/2011	51,000	$ 4.22
Natural Gas	01/2002 to 12/2012	60,000	$ 3.74

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 under our credit facility. The credit facility 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 facility 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, 2003, the interest rate on the entire outstanding principal balance under our credit facility was fixed at 3.21% through February 6, 2004. On February 6, 2004, the interest rate on the entire outstanding principal balance was fixed at 3.2% through August 6, 2004. At December 31, 2003, the carrying amount approximated fair market value. Assuming a constant debt level of $185.0 million, the cash flow impact for 2004 resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $745,000.

Item 8. Financial Statements and Supplementary Data

WHITING PETROLEUM CORPORATION
INDEX TO FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Whiting Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and Subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of income, stockholder's equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the 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.

/s/ DELOITTE & TOUCHE LLP

February 25, 2004
Denver, Colorado

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2003 AND 2002

In thousands, except per share data

	2003	2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 53,585	$ 4,833
Accounts receivable trade	24,020	22,509
Income taxes and other receivables	-	8,162
Prepaid expenses and other	2,666	3,542
Total current assets	80,271	39,046
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	615,764	553,902
Unproved properties	1,637	1,593
Other property and equipment	2,684	3,454
Total property and equipment	620,085	558,949
Less accumulated depreciation, depletion and amortization	(192,794)	(154,352)
Property and equipment—net	427,291	404,597
OTHER LONG-TERM ASSETS	9,988	4,825
DEFERRED INCOME TAX ASSET	18,735	
TOTAL	$ 536,285	$ 448,468

(Continued)

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2003 AND 2002

In thousands, except per share data

	2003	2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 15,918	$ 8,474
Oil and gas sales payable	2,406	903
Accrued employee benefits	5,275	4,259
Production taxes payable	2,574	2,137
Derivative liability	2,145	3,300
Income taxes and other liabilities	693	585
Total current liabilities	29,011	19,658
DEFERRED INCOME TAX LIABILITY	-	28,235
ABANDONMENT LIABILITY	23,021	4,232
PRODUCTION PARTICIPATION PLAN LIABILITY	7,868	8,053
TAX SHARING LIABILITY	28,790	-
LONG-TERM DEBT	188,017	265,472
COMMITMENTS AND CONTINGENCIES (Note 7)		
STOCKHOLDERS' EQUITY:		
Common stock, $.001 par value; 18,750,000 authorized, issued and outstanding	19	19
Additional paid-in capital	170,367	53,219
Accumulated other comprehensive loss	(223)	(1,550)
Retained earnings	89,415	71,130
Total stockholders' equity	259,578	122,818
TOTAL	$ 536,285	$ 448,468

See notes to consolidated financial statements. (Concluded)

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

In thousands, except per share data

	2003	2002	2001
REVENUES:			
Oil and gas sales	$ 175,731	$ 122,709	$ 125,286
Gain (loss) on oil and gas hedging activities	(8,680)	(3,184)	2,266
Gain on sale of oil and gas properties	-	978	11,698
Interest income and other	330	9	205
Total Revenues	167,381	120,512	139,455
COSTS AND EXPENSES:			
Lease operating	43,213	32,867	29,767
Production taxes	10,691	7,363	6,482
Depreciation, depletion and amortization	41,256	43,601	26,904
Exploration	3,186	1,811	793
General and administrative	12,805	11,980	10,939
Phantom equity plan	10,914	-	-
Interest expense	9,177	10,938	10,233
Total costs and expenses	131,242	108,560	85,118
INCOME BEFORE INCOME TAXES	36,139	11,952	54,337
INCOME TAX EXPENSE (BENEFIT):			
Current	2,389	(6,408)	1,815
Deferred	11,560	10,631	11,279
Total income tax expense	13,949	4,223	13,094
INCOME FROM CONTINUING OPERATIONS	22,190	7,729	41,243
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	(3,905)	-	-
NET INCOME	$ 18,285	$ 7,729	$ 41,243
Basic and diluted earnings per share from continuing operations	$ 1.18	$ 0.41	$ 2.20
Cumulative change in accounting principle	(0.20)	-	-
BASIC AND DILUTED NET INCOME PER COMMON SHARE	$ 0.98	$ 0.41	$ 2.20
WEIGHTED AVERAGE SHARES OUTSTANDING	18,750	18,750	18,750

See notes to consolidated financial statements.

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

In thousands

	Common Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive	Total Stockholders'	Comprehensive
	Shares	Amount	Capital	Earnings	Income (Loss)	Equity	Income
BALANCES–January 1, 2001	18,750	$ 19	$ 47,856	$ 22,158	$ 15	$ 70,048	-
Net income	-	-	-	41,243	-	41,243	41,243
Unrealized net gain on marketable equity securities for sale	-	-	-	-	88	88	88
Reclass to earnings	-	-	-	-	87	87	87
BALANCES–December 31, 2001	18,750	19	47,856	63,401	190	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	71,130	(1,550)	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	$ 89,415	$ (223)	$ 259,578	$ 19,612

See notes to consolidated financial statements.

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

In thousands

	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 18,285	$ 7,729	$ 41,243
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of oil and gas properties	-	(978)	(11,700)
Depreciation, depletion and amortization	41,256	43,601	35,902
Deferred income taxes	11,560	10,631	11,288
Amortization of bank fees	1,091	71	-
Accretion of tax sharing agreement	220	-	-
Phantom equity plan	6,510	-	-
Cumulative change in accounting principle	3,905	-	-
Changes in assets and liabilities:			
Accounts receivable	(307)	(1,129)	2,165
Income taxes and other receivable	3,814	1,538	(5,670)
Other assets	295	(1,229)	315
Abandonment liability	(147)	(48)	(8,997)
Production participation plan	651	1,685	1,473
Current liabilities	9,229	710	(3,672)
Net cash provided by operating activities	96,362	62,581	62,347
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(47,555)	(165,443)	(99,621)
Acquisition of partnership interests, net of cash received	(4,453)	-	-
Proceeds from sale of properties	-	1,534	19,570
Restricted cash	-	6,434	(6,434)
Net cash used in investing activities	(52,008)	(157,475)	(86,485)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Other advances (repayments) from Alliant, net	4,616	(83,119)	23,869
Proceeds from bank loan	-	185,000	-
Debt issuance costs	(218)	(3,171)	-
Net cash provided by financing activities	4,398	98,710	23,869
NET CHANGE IN CASH AND CASH EQUIVALENTS	48,752	3,816	(269)
CASH AND CASH EQUIVALENTS:			
Beginning of period	4,833	1,017	1,286
End of period	$ 53,585	$ 4,833	$ 1,017
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid (refunded) for income taxes—Alliant	$ (1,425)	$ (7,946)	$ 8,586
Cash paid for interest	$ 6,464	$ 10,866	$ 10,233
NONCASH FINANCING ACTIVITIES:			
Alliant debt converted to equity	80,931	-	-

See notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

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 Gulf Coast/Permian Basin, Rocky Mountains, Michigan, and Mid-Continent 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 related party debt and bank loan have a recorded value that approximates its fair value as both instruments have variable interest rates tied to current market rates. 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 have not experienced material credit losses. The Company believes that our 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 our 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, 2003, 2002 or 2001.

At December 31, 2003 and 2002, the Company had recorded an allowance for doubtful accounts of $300 and $250 and, 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 a period of time to be readied for their intended use. During 2003, 2002 and 2001, capitalized interest was insignificant.

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 2003, 2002 and 2001, the Company did not record any impairment charges for 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, 2003 and 2002, the balance of other property and equipment was $2,684 and $3,454, respectively. Depreciation expense was approximately $836, $770, and $710 for the years ended December 31, 2003, 2002 and 2001, 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 $5,631, $5,505 and $5,276, for the years ended December 31, 2003, 2002 and 2001, 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. In situations where gas imbalances occur, receivables are valued at current market value each reporting period, while liabilities are generally presented based on the price in effect when the imbalance occurred. As of December 31, 2003 and 2002, the Company was in an under produced imbalance position of approximately 206,000 Mcf and 411,000 Mcf.

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 2003, 2002 and 2001, Whiting entered into a number of oil and gas swaps and forward contracts.

At December 31, 2003, the Company had five commodity swaps or forward 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.

At December 31, 2002, the Company had four commodity swaps or forward contracts outstanding with a fair market value unrealized loss of $3,300 of which $1,980 was recorded as a component of accumulated other comprehensive loss and $1,320 was recorded as a reduction to the deferred tax liability.

For the years ended December 31, 2003, 2002, and 2001, Whiting recognized a loss of approximately $8.7 million, a loss of approximately $3.2 million, and a gain of $2.3 million from the settlement of derivative instruments, respectively.

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 and 2002, 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 and $1,300, respectively. 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. As of December 31, 2002, the Company recorded an unrealized holding gain of $715 of which $430 was recorded as a component of accumulated other comprehensive income and $285 was recorded as a deferred tax liability.

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.

Earnings Per Share—Basic net income per common share of stock is calculated by dividing net income by the weighted average 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 of common shares outstanding and other dilutive securities. There were no potentially dilutive securities of the Company outstanding for any of the periods presented.

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 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 June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, Business Combinations which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, Goodwill and Other Intangible Assets, which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The Company did not change or reclassify contractual mineral rights included in oil and gas properties on the balance sheet upon adoption of SFAS No. 142. The Company believes the current accounting of such mineral rights as part of crude oil and natural gas properties is appropriate under the successful efforts method of accounting. However, there is an alternative view that reclassification of mineral rights to an intangible assets may be necessary. If a reclassification of contractual mineral rights acquired subsequent to July 1, 2001 from oil and gas properties to long term intangible assets is required, then the reclassified amount as of December 31, 2003 and 2002 would be approximately $160.1 million and $161.2 million, respectively. Management does not believe that the ultimate outcome of this issue will have a significant impact on the Company's cash flows, results of operations or financial condition.

In June 2002 the FASB issued SFAS No. 146, Accounting for Costs Associates with Exit or Disposal Activities. This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of this Statement had no impact on the financial statements.

FASB Interpretation No. 45 (FIN 45), Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others was issued in November 2002, by the FASB. FIN 45 requires a guarantor to recognize a liability for the fair value of the obligation it assumes under certain guarantees. Additionally, FIN 45 requires a guarantor to disclose certain aspects of each guarantee, or each group of similar guarantees, including the nature of the guarantee, the maximum exposure under the guarantee, the current carrying amount of any liability for the guarantee, and any recourse provisions allowing the guarantor to recover from third parties any amounts paid under the guarantee. The disclosure provisions of FIN 45 are effective for financial statements for both interim and annual periods ending after December 15, 2002. The fair value measurement provisions of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The adoption of this Statement did not have a material impact on the financial statements. Under the disclosure provisions, 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, 2004 increased to 50% of the actual price received in excess of $19.77 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. As of December 31, 2003, the Company has paid $3.1 million under this agreement and has accrued an additional $215 as currently payable.

In January 2003, the FASB issued FASB Interpretation No. 46 (as revised in December 2003), Consolidation of Variable Interest Entities (FIN 46). FIN 46 clarifies the application of Accounting Research Bulletin No. 51, Consolidated Financial Statements to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated support from other parties. FIN 46 requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. All companies with interests in variable interest entities created after January 31, 2003, shall apply the provisions of FIN 46 to those entities immediately. The adoption of this Statement had no impact on the Company's financial statements.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities to amend and clarify financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. The changes in this statement require that contracts with comparable characteristics be accounted for similarly to achieve more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and will be applied prospectively. The adoption of this Statement had no impact on the financial statements.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity to classify certain financial instruments as liabilities in statements of financial position. The financial instruments are mandatorily redeemable shares, which the issuing company is obligated to buy back in exchange for cash or other assets, put options and forward purchase contracts, instruments that do or may require the issuer to buy back some of its shares in exchange for cash or other assets, and obligations that can be settled with shares, the monetary value of which is fixed, tied solely or predominantly to a variable such as a market index, or varies inversely with the value of the issuers' shares. Most of the guidance in SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The adoption of this Statement had no impact on the financial statements.

2. *ASSET RETIREMENT OBLIGATIONS*

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 changes in the estimated asset retirement obligation from the amount recorded upon adoption of SFAS No. 143 on January 1, 2003 (including its previously recognized liability in California) through December 31, 2003.

Beginning asset retirement obligation	$	4,232
SFAS 143 adoption		16,458
Additional liability incurred		996
Accretion expense		1,482
Liabilities settled		(147)
Ending asset retirement obligation	$	23,021

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

3. *INVESTMENT IN PARTNERSHIPS*

The Company sponsors 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. Additionally, Whiting is a general partner in various partnerships which own and operate transportation and gas processing facilities. 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.

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, $10.5 million and $10.2 million, in interest expense related to this note during the years ended December 31, 2003, 2002 and 2001, 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 from/to affiliates represent the net amount of advances to partnerships for property development offset by proceeds on sales of property and cash receipts from the sale of oil and gas to be distributed to the partnerships.

5. *LONG-TERM DEBT*

Long-term debt consisted of the following at December 31, 2003 and 2002:

	2003	**2002**
Bank borrowings	$ 185,000	$ 185,000
Alliant—see Note 4	3,017	80,472

Credit Facility— The Company has a $350.0 million credit agreement with a syndicate of banks. At December 31, 2003, the credit agreement provided a borrowing base of $210.0 million with an outstanding principal balance of $185.0 million. On February 17, 2004, the Company repaid $40.0 million of the outstanding principal balance from cash on hand in excess of projected drilling and production needs. The borrowing base under the credit agreement is based on the collateral value of the Company's proved reserves and is subject to redetermination on May 1 and November 1 of each year. If the borrowing base is determined to be lower than the outstanding principal balance then drawn, the Company must immediately pay the difference. The credit agreement provides for interest only payments until December 20, 2005, when the entire amount borrowed is due. Interest accrues, at the Company'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 0.25% to 1.0% depending on the ratio of the amounts borrowed to the borrowing base, or (2) at the LIBOR rate plus a margin where the margin varies from 1.5% to 2.25% depending on the ratio of the amounts borrowed to the borrowing base. At December 31, 2003, all amounts outstanding under the credit agreement bore interest at an annual rate of 3.21% through February 6, 2004.

On February 6, 2004, the Company fixed the rate on the outstanding principal balance at an annual rate of 3.2% through August 6, 2004. The credit agreement has covenants that restrict the payment of cash dividends, borrowings, sale of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders and requires the Company to maintain certain debt to EBITDAX (as defined in our credit agreement) ratios and a working capital ratio. The credit agreement also precludes the Company from providing any cash to Alliant Energy except for services rendered on an arm's-length basis or for income taxes. The Company was in compliance with the covenants under the credit agreement as of December 31, 2003. The credit agreement is secured by a first lien on substantially all of Whiting's assets.

6. *EMPLOYEE BENEFIT PLANS*

The Company has a Production Participation Plan for all employees. On an annual basis, management and the Board of Directors allocate interests in oil and gas properties acquired or developed during the year to the plan on a discretionary basis. Once allocated, the interests (not legally conveyed) are fixed and plan participants generally vest ratably over five years. Forfeitures are re-allocated among other Plan participants. Allocations prior to 1995 consisted of 2% - 3% overriding royalty interests. Allocations since 1995 have been 2% - 5% net revenue interests.

Payments to participants of the plan are made annually in cash after year end and amounted to $4.4 million, $3.6 million and $4.1 million for 2003, 2002 and 2001, respectively. The Company has estimated the total discounted obligations, including the amounts above, at December 31, 2003 and 2002 as being $12.3 million and $11.7 million, respectively. Plan expense for 2003, 2002 and 2001 was approximately $4.3 million, $5.3 million and $5.6 million, respectively.

The Company's Board of Directors adopted the Whiting Petroleum Corporation 2003 Equity Incentive Plan on September 17, 2003. Two million shares of the Company's common stock have been reserved for issuance under this plan. 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. As of December 31, 2003, no awards had been made under this 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 is reflected as an increase to additional paid-in capital. The phantom equity plan is now terminated.

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 2003, 2002 and 2001 were approximately $665, $529 and $287, respectively. Employer contributions vest ratably at 20% per year over a five year period.

7. *COMMITMENTS AND CONTINGENCIES*

The Company leases administrative office space under an operating lease arrangement through October 2005. Net rental expense for 2003, 2002, and 2001 amounted to approximately $1,046, $916 and $823, respectively. A summary of future minimum lease payments under this noncancellable-operating lease as of December 31, 2003 is as follows (in thousands):

Year Ending December 31,	
2004	$ 1,084
2005	929
Total	$ 2,013

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.

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 $62 million. The Company has estimated total payments to Alliant will approximate $49 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 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. There is a provision in the Tax Separation Agreement that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in a corresponding adjustment of the Alliant 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):

	2003	2002	2001
Expected statutory tax expense at 35%	$ 12,649	$ 4,183	$ 19,018
Research and Section 29 tax credits	-	(178)	(6,575)
Excess percentage depletion	(216)	(82)	(268)
State tax expense, net of federal benefit	1,516	300	918
	$ 13,949	$ 4,223	$ 13,093

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):

	2003	2002
Oil and gas properties	$ (2,893)	$ (32,290)
Production participation plan	2,993	3,020
Available for sale securities	(127)	(285)
Derivative instruments	828	1,320
Tax sharing agreement	11,028	-
Abandonment obligations	3,028	-
Net operating loss carryforward	3,878	-
	$ 18,735	$ (28,235)

The Company's net operating loss will expire in 2023.

9. *OIL AND GAS ACTIVITIES*

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

	2003	2002	2001
Unproved property acquisition	$ 242	$ 851	$ 105
Proved property acquisition	10,914	140,708	66,024
Development	40,336	23,136	32,073
Exploration	3,186	1,811	793
Subtotal	54,678	166,506	98,995
Asset retirement obligations	996	-	-
Total	$ 55,674	$ 166,506	$ 98,995

During 2003, additions to oil and gas properties of approximately $996 were recorded for the estimated costs 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):

	2003	2002
Proven oil and gas properties	$ 615,764	$ 553,902
Unproven oil and gas properties	1,637	1,593
Accumulated depreciation, depletion and amortization	(191,488)	(152,595)
Oil and gas properties—net	$ 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

10. *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.

The Company's oil and gas reserves are attributable solely 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, 2003, 2002 and 2001, are as follows:

	Oil (MBbls)	Gas (MMcf)
Balance—January 1, 2001	19,121	157,521
Extensions and discoveries	1,086	9,320
Sales of minerals in place	(677)	(6,045)
Purchases of minerals in place	945	89,760
Production	(2,088)	(19,751)
Revisions to previous estimates	(3,582)	(3,284)
Balance—December 31, 2001	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
Proved developed reserves:		
December 31, 2001	11,046	136,817
December 31, 2002	23,784	167,618
December 31, 2003	26,157	171,881

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 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):

	2003	2002	2001
Future cash flows	$ 2,297,935	$ 1,854,886	$ 880,890
Future production costs	(879,390)	(677,146)	(379,732)
Future development costs	(66,326)	(65,440)	(75,575)
Future income tax expense	(336,165)	(270,516)	(62,025)
Future net cash flows	1,016,054	841,784	363,558
10% annual discount for estimated timing of cash flows	(426,490)	(365,755)	(151,823)
Standardized measure of discounted future net cash flows	$ 589,564	$ 476,029	$ 211,735

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 $145 in 2003 and $1,300 in 2002 and $0 in 2001, respectively.

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

	2003	2002	2001
Beginning of year:	$ 476,029	$ 211,735	$ 519,197
Sale of oil and gas produced, net of production costs	(121,827)	(80,337)	(87,273)
Sales of minerals in place	-	(739)	(11,200)
Net changes in prices and production costs	108,115	212,191	(528,096)
Extensions, discoveries and improved recoveries	47,183	6,587	17,511
Development costs-net	(886)	(11,328)	(3,322)
Purchases of mineral in place	16,745	241,798	84,613
Revisions of previous quantity estimates	43,679	(36,164)	(16,205)
Net change in income taxes	(42,082)	(116,854)	183,051
Accretion of discount	62,901	24,786	73,516
Changes in production rates and other	(293)	24,354	(20,057)
End of year	$ 589,564	$ 476,029	$ 211,735

Average wellhead prices in effect at December 31, 2003, 2002 and 2001 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows (in thousands):

	2003	2002	2001
Oil (per Bbl)	$ 29.43	$ 28.21	$ 17.30
Gas (per Mcf)	$ 5.52	$ 4.39	$ 2.72

11. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2003, 2002, and 2001 (in thousands except per share data) (in thousands):

	Three Months Ended			
	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
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 net income (loss) per share	0.19	0.38	0.43	(0.02)

	Three Months Ended			
	March 31, 2002	June 30, 2002	September 30, 2002	December 31, 2002
Year ended December 31, 2002:				
Oil and gas sales	$ 20,190	$ 29,552	$ 34,657	$ 38,310
Income (loss) before income tax	(2,977)	3,277	6,191	5,461
Net income	(1,822)	2,050	3,877	3,624
Basic net income (loss) per share	(0.10)	0.11	0.21	0.19

12. SUBSEQUENT EVENT

On February 2, 2004, Whiting announced that the Company entered into a definitive merger agreement to acquire Equity Oil Company. The merger agreement provides for a stock-for-stock merger under which Equity shareholders will receive a fixed exchange ratio of 0.185 shares of Whiting common stock for each share of Equity common stock that they own. In addition, Whiting will assume approximately $29 million of Equity debt. The merger is subject to the approval of shareholders owning two-thirds of the outstanding Equity shares and other customary closing conditions. Equity intends to call a special meeting of its shareholders during the second quarter of 2004 to consider and vote on the merger. The Company expects to complete the merger as soon as practicable following approval by Equity's shareholders.

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, 2003. 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, 2003 to ensure that 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.

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, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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 2004 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 10 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 have also adopted corporate governance guidelines and written charters for our Audit, Compensation and Nominating and Governance Committees and have posted copies of those documents on our website at www.whiting.com. Copies of these documents are also available in print to any stockholder who requests them in writing from the Corporate Secretary of Whiting Petroleum Corporation.

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

The following table sets forth information with respect to compensation plans under which equity securities of Whiting Petroleum Corporation are authorized for issuance as of December 31, 2003.

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	2,000,000
Equity compensation plans not approved by security holders	-----	N/A	-----
Total	-----	N/A	2,000,000

(1) Includes only the Company's 2003 Equity Incentive Plan.

Item 13. Certain Relationships and Related Transactions

Not applicable.

Item 14. Principal Accountant 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, and Reports on Form 8-K

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

a. Independent Auditors' Report

b. Consolidated Balance Sheets as of December 31, 2003 and 2002

c. Consolidated Statements of Income for the Years ended December 31, 2003, 2002 and 2001

d. Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Years ended December 31, 2003, 2002 and 2001

e. Consolidated Statements of Cash Flows for the Years ended December 31, 2003, 2002 and 2001

f. Notes to Consolidated Financial Statements

2. Financial statement schedules – All 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 and 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) Reports on Form 8-K

None.

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 4th day of March, 2004.

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)	March 4, 2004
/s/ James R. Casperson James R. Casperson	Chief Financial Officer (Principal Financial Officer)	March 4, 2004
/s/ Michael J. Stevens Michael J. Stevens	Controller and Treasurer (Principal Accounting Officer)	March 4, 2004
/s/ Thomas L. Aller Thomas L. Aller	Director	March 4, 2004
/s/ Graydon D. Hubbard Graydon D. Hubbard	Director	March 4, 2004
/s/ J. B. Ladd J. B. Ladd	Director	March 4, 2004
/s/ Kenneth R. Whiting Kenneth R. Whiting	Director	March 4, 2004

EXHIBIT INDEX

Exhibit Number	Exhibit Description
(2)	Agreement and Plan of Merger, dated February 1, 2004, by and among Whiting Petroleum Corporation, WPC Equity Acquisition Corp. and Equity Oil Company. [Incorporated by reference to Exhibit 10.1 to Equity Oil Company's Current Report on Form 8-K dated February 2, 2004 (File No. 000 00610)]. Schedules and exhibits to the Agreement and Plan of Merger have not been filed herewith. The registrant agrees to furnish a copy of any omitted schedule or exhibit to the Securities and Exchange Commission upon request.
(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)	Amendment to Amended and Restated By-laws of Whiting Petroleum Corporation.
(4.1)	Credit Agreement, dated as of December 20, 2002, among Whiting Oil and Gas Corporation (f/k/a Whiting Petroleum Corporation), the financial institutions listed therein, Bank One, NA, as Administrative Agent, and Wachovia Bank, N.A., as Syndication Agent [Incorporated by reference to Exhibit 10.5 to Alliant Energy Corporation's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 1-9894)].
(4.2)	First Amendment to Credit Agreement, effective as of January 7, 2003, among Whiting Oil and Gas Corporation (f/k/a Whiting Petroleum Corporation), Bank One, NA, as Administrative Agent, and the financial institutions party thereto [Incorporated by reference to Exhibit 10.5a to Alliant Energy Corporation's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 1-9894)].
(4.3)	Second Amendment to Credit Agreement, effective as of June 30, 2003, among Whiting Oil and Gas Corporation (f/k/a Whiting Petroleum Corporation), Bank One, NA, as Administrative Agent, and the financial institutions party thereto [Incorporated by reference to Exhibit 4.4 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(4.4)	Third Amendment to Credit Agreement, dated as of October 24, 2003, among Whiting Oil and Gas Corporation, Bank One, NA, as Administrative Agent, and the financial institutions party thereto [Incorporated by reference to Exhibit 4.5 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.1)*	Whiting Oil and Gas Corporation Phantom Equity Plan, as amended and restated [Incorporated by reference to Exhibit 10.10 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.2)*	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)].
(10.3)*	Whiting Oil and Gas Corporation Production Participation Plan [Incorporated by reference to Exhibit 10.5 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.4)*	First Amendment to Whiting Oil and Gas Corporation Production Participation Plan [Incorporated by reference to Exhibit 10.6 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.5)*	Second Amendment to Whiting Oil and Gas Corporation Production Participation Plan [Incorporated by reference to Exhibit 10.7 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.6)*	Third Amendment to Whiting Oil and Gas Corporation Production Participation Plan [Incorporated by reference to Exhibit 10.8 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.7)*	Fourth Amendment to Whiting Oil and Gas Corporation Production Participation Plan [Incorporated by reference to Exhibit 10.9 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.8)	Master Separation Agreement among Alliant Energy Corporation, Alliant Energy Resources, Inc., Whiting Petroleum Corporation and Whiting Oil and Gas Corporation [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.9)	Registration Rights Agreement among Alliant Energy Corporation, Alliant Energy Resources, Inc. and Whiting Petroleum Corporation [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.10)	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)].
(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 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 Chief Financial Officer pursuant to 18 U.S.C. Section 1350

(99.1) Proxy Statement for the 2004 Annual Meeting of Stockholders, to be filed within 120 days of December 31, 2003 [To be filed with the Securities and Exchange Commission under Regulation 14A within 120 days after December 31, 2003; except to the extent specifically incorporated by reference, the Proxy Statement for the 2004 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.

SUBSIDIARIES OF WHITING PETROLEUM CORPORATION

Name	Jurisdiction of Incorporation or Organization	Percent Ownership
Whiting Oil and Gas Corporation	Delaware	100%
Whiting Programs, Inc.	Delaware	100%
Whiting-Golden Gas Production Company	Oklahoma	100%
WOK Acquisition Company	Delaware	100%
Whiting 1985 Production Partnership, Ltd.	Texas	100%
Whiting-State Street Production Partnership, Ltd.	Texas	100%
Whiting-FBC Production Partnership, Ltd.	Texas	100%
Whiting-High Street Production Partnership, Ltd.	Texas	100%
Whiting-Park Production Partnership, Ltd.	Texas	16%
Whiting-Madison Production Partnership, Ltd.	Texas	16%
Whiting 1988 Production Limited Partnership, Ltd.	Texas	13%

Exhibit 31.1

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)) 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) 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
   c) 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: March 4, 2004

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

Exhibit 31.2

CERTIFICATIONS

I, James R. Casperson, 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)) 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) 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
   c) 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: March 4, 2004

/s/ James R. Casperson

James R. Casperson
Chief Financial Officer

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, 2003 (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: March 4, 2004

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 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, 2003 (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
Chief Financial Officer

Dated: March 4, 2004

EXECUTIVE OFFICERS

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

D. Sherwin Artus
Senior Vice President

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

James T. Brown
Vice President, Operations

John R. Hazlett
Vice President, Acquisitions and Land

Mark R. Williams
Vice President, Exploration and Development

Patricia J. Miller
Vice President-Human Resources and
Investor Relations, Corporate Secretary

Michael J. Stevens
Controller and Treasurer

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

* 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:

Patricia J. Miller
Vice President-Human Resources and
Investor Relations, Corporate Secretary

Heather M. Duncan
Director-Human Resources and Investor Relations

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 2003 Annual Report on Form 10-K as filed with the Securities and Exchange Commission.

ANNUAL MEETING

Tuesday, May 4, 2004 at 10:00 am
Wells Fargo Center - John D. Hershner Room
1700 Lincoln Street, Denver, Colorado

COMMON STOCK

QUARTERLY PRICE RANGE

2003	High	Low
4th quarter (11/20-12/31)	$18.54	$16.15

1700 Broadway, Suite 2300
Denver, Colorado 80290-2300
Tel: (303) 837-1661
Fax: (303) 861-4023

www.whiting.com