CONTINENTAL RESOURCES INC
Form 10-K
March 17, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

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: 001-32886

CONTINENTAL RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
302 N. Independence, Suite 1500, Enid, Oklahoma	**73701**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (580) 233-8955

Securities registered under Section 12(b) of the Exchange Act:

Title of Class	Name of Exchange on Which Registered
Common Stock, $0.01 par value	New York Stock Exchange

Securities registered under Section 12(g) of the Exchange Act: None

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

Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

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. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of accelerated filer , large accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x	Smaller reporting company ¨

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked prices of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter. As of June 30, 2007 aggregate market value was $713,522,464.

As of February 29, 2008, the registrant had 169,073,371 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Continental Resources, Inc. for the Annual Meeting of Stockholders to be held May 27, 2008, which will be filed with the Commission no later than April 29, 2008 are incorporated by reference into Part III of this Form 10-K.

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Glossary of Oil and Natural Gas Terms

The terms defined in this section are used throughout this report:

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Basin. A large natural depression on the earth s surface in which sediments generally brought by water accumulate.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Enhanced recovery. The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differ from nearby rock.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

Infill wells. Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

MBoe. One thousand Boe.

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MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

Net acres. The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

PUD. Proved undeveloped

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV-10 is a non-GAAP financial measure.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves (PUD). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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

Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

Standardized Measure. Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Waterflood. The injection of water into an oil reservoir to push additional oil out of the reservoir rock and into the wellbores of producing wells. Typically an enhanced recovery process.

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Wellbore. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

Working interest. The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Cautionary Statement Regarding Forward-Looking Statements

This report contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to identify forwa statements, although not all forward-looking statements contain such identifying words. Except as otherwise specifically indicated, these statements assume no significant changes will occur in the operating environment for oil and natural gas properties and the there will be no material acquisitions, divestitures or financings except as otherwise described.

Forward-looking statements may include statements about our:

business strategy;

reserves;

technology;

financial strategy;

oil and natural gas realized prices;

timing and amount of future production of oil and natural gas;

the amount, nature and timing of capital expenditures;

drilling of wells;

competition and government regulations;

marketing of oil and natural gas;

exploitation or property acquisitions;

- costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this report. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Item 1A. Risk Factors and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation and elsewhere in this report. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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Part I

You should read this entire report carefully, including Risk Factors and our historical consolidated financial statements and the notes to those historical consolidated financial statements included elsewhere in this report. Unless the context otherwise requires, references in this report to Continental Resources, we, us, our, ours or company refer to Continental Resources, Inc.

Item 1. Business

General

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We were originally formed in 1967 to explore, develop and produce oil and natural gas properties. Through 1993, our activities and growth remained focused primarily in Oklahoma. In 1993, we expanded our activity into the Rocky Mountain and Gulf Coast regions. Approximately 82% of our estimated proved reserves as of December 31, 2007 are located in the Rocky Mountain region. We completed an initial public offering of our common stock on May 14, 2007, and began trading on the New York Stock Exchange on May 15, 2007 under the ticker symbol CLR .

We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 89.0 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2003 through December 31, 2007 compared to 0.9 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2007, our estimated proved reserves were 134.6 MMBoe, with estimated proved developed reserves of 101.2 MMBoe, or 75% of our total estimated proved reserves. Crude oil comprised 77% of our total estimated proved reserves. For the year ended December 31, 2007, we generated revenues of $582.2 million, and operating cash flows of $390.6 million. For the year and quarter ended December 31, 2007, daily production averaged 29,099 and 30,369 Boe per day, respectively. This represents growth of 18% and 15% as compared to the year and quarter ended December 31, 2006, when daily production averaged 24,706 and 26,503, respectively.

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The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2007, average daily production for the three months ended December 31, 2007 and the reserve-to-production index in our principal regions. Our reserve estimates as of December 31, 2007 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 85% of our PV-10. Our technical staff evaluated properties representing the remaining 15% of our PV-10.

	At December 31, 2007						
	Proved reserves (MBoe)	Percent of total	PV-10(1) (in millions)	Net producing wells	Average daily Production fourth quarter 2007 (Boe per day)	Percent of Total	Annualized reserve/ production index(2)
Rockies:							
Red River units	67,856	50%	$ 1,991	233	14,374	47%	12.9
Bakken field							
Montana Bakken	27,132	20%	713	83	7,244	24%	10.3
North Dakota Bakken	6,058	5%	149	21	1,382	5%	12.0
Other	8,920	7%	208	224	1,600	5%	15.3
Mid-Continent:							
Arkoma Woodford	8,919	7%	138	16	1,338	4%	18.3
Other	15,452	11%	319	712	3,767	13%	11.2
Gulf Coast	278	0%	10	17	664	2%	1.1
Total	134,615	100%	$ 3,528	1,306	30,369	100%	12.1

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. The Standardized Measure at December 31, 2007 is $2.6 billion, a $0.9 billion difference from PV-10 because of the tax effect. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2007 production into the proved reserve quantity at December 31, 2007.

The following table provides additional information regarding our key development areas:

	Developed acres		Undeveloped acres		Gross wells planned for drilling in 2008	Capital Expenditures (in millions)(1)
	Gross	Net	Gross	Net		
Rockies:						
Red River units	144,487	129,168			40	$ 168
Bakken field						
Montana Bakken	78,003	60,074	86,488	64,536	17	55
North Dakota Bakken	46,968	24,546	553,516	271,667	74	125
Other	58,881	44,480	301,980	176,250	20	29
Mid-Continent:						
Arkoma Woodford	41,216	8,625	104,001	35,759	139	103
Other	136,214	93,567	296,908	179,448	57	46
Gulf Coast	41,010	11,869	16,205	5,472	9	21
Total	546,779	372,329	1,359,098	733,132	356	$ 547

(1) Capital expenditures budgeted for 2008 but excludes budgeted amounts for land of $39 million, seismic of $17 million, and $13 million for vehicles, computers and other equipment.

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Our Business Strategy

Our goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of our business strategy are:

Focus on Oil. During the late 1980 s we began to believe that the valuation potential for crude oil exceeded that of natural gas. Accordingly, we began to shift our reserve and production profiles towards crude oil. As of December 31, 2007, crude oil comprises 77% of our total proved reserves and 82% of our 2007 annual production. Although we do pursue natural gas opportunities, we continue to believe that crude oil valuations will remain superior to natural gas valuations on a relative Btu basis.

Growth Through Low-Cost Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions. From January 1, 2003 through December 31, 2007, proved oil and natural gas reserve additions through extensions and discoveries were 89.0 MMBoe compared to 0.9 MMBoe of proved reserve purchases.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. As an early entrant in new or emerging plays, we expect to acquire undeveloped acreage at a lower cost than those of later entrants into a developing play.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite, Bakken Shale and Arkoma Woodford formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technology. Our production from the Red River units, the Bakken field, and the Arkoma Woodford comprised approximately 8,310 MBoe, or 78% of our total oil and natural gas production during the year ended December 31, 2007.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 465,207 net undeveloped acres held in the Montana and North Dakota Bakken shale and Arkoma Woodford fields, we held 171,475 net undeveloped acres in other oil and natural gas shale plays as of December 31, 2007. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

Our Business Strengths

We have a number of strengths that we believe will help us successfully execute our strategies:

Large Acreage Inventory. We own 733,132 net undeveloped and 372,329 net developed acres as of December 31, 2007. Approximately 72% of the undeveloped acres are found within unconventional shale resource plays including the Bakken shale in North Dakota and Montana and the Woodford shale in southeast Oklahoma. The balance of the locations and undeveloped acreage is found in other emerging unconventional resource plays including the Woodford and Atoka of western Oklahoma and the Red River of South Dakota as well as more conventional plays including 3D defined locations for the Trenton-Black River of Michigan, Red River of Montana, and Frio in South Texas.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 460 horizontal wells since that time. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 48 waterflood units. Additionally, we operate eight high pressure air injection (HPAI) floods in the United States.

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Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2007, we operated properties comprising 93% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our seven senior officers have an average of 27 years of oil and gas industry experience. Additionally, our technical staff, which includes 21 petroleum engineers, 16 geoscientists and 10 landmen, has an average of 19 years experience in the industry.

Strong Financial Position. As of February 29, 2008, we had outstanding borrowings under our credit facility of approximately $222.0 million and available capacity under our selected commitment level of $178.0 million. We have elected to set the commitment level at $400 million, which is below the established borrowing base of $600 million, in order to minimize commitment fees. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows and borrowings under our credit facility.

Oil and Gas Operations

Proved Reserves

The following tables set forth our estimated proved oil and natural gas reserves, percent of total proved reserves that are proved developed, the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2007 by reserve category and region. Ryder Scott Company, L.P., our independent petroleum engineers, evaluated properties representing approximately 85% of our PV-10, and our technical staff evaluated the remaining properties. The year-end weighted average oil and natural gas prices used in the computation of future net cash flows at December 31, 2007 were $82.86 per barrel and $6.14 per Mcf, respectively.

	December 31, 2007			
	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	PV-10[1] (in millions)
Proved developed producing	78,178	126,419	99,248	$ 2,629
Proved developed non-producing	1,578	2,412	1,980	36
Proved undeveloped	24,389	53,988	33,387	863
Total proved reserves	104,145	182,819	134,615	$ 3,528
Standardized measure				$ 2,582

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	% Proved developed	PV-10[1] (in millions)
Rockies:					
Red River units	62,383	32,838	67,856	81%	$ 1,991
Bakken field					
Montana Bakken	22,704	26,565	27,132	74%	713
North Dakota Bakken	5,218	5,040	6,058	59%	149
Other	7,966	5,726	8,920	73%	208
Mid-Continent:					
Arkoma Woodford		53,513	8,919	15%	138
Other	5,753	58,196	15,452	85%	319
Gulf Coast	121	941	278	100%	10
Total	104,145	182,819	134,615	75%	$ 3,528

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(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. The Standardized Measure at December 31, 2007 is $2.6 billion, a $0.9 billion difference from PV-10 because of the tax effect. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2007:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units	144,487	129,168			144,487	129,168
Bakken field						
Montana Bakken	78,003	60,074	86,488	64,536	164,491	124,610
North Dakota Bakken	46,968	24,546	553,516	271,667	600,484	296,213
Other	58,881	44,480	301,980	176,250	360,861	220,730
Mid-Continent:						
Arkoma Woodford	41,216	8,625	104,001	35,759	155,906	52,371
Other	136,214	93,567	296,908	179,448	422,433	265,028
Gulf Coast	41,010	11,869	16,205	5,472	57,215	17,341
Total	546,779	372,329	1,359,098	733,132	1,905,877	1,105,461

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2007 that will expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units						
Bakken field						
Montana Bakken	54,998	38,202	14,536	11,462	6,050	5,122
North Dakota Bakken	122,881	54,211	228,444	115,665	110,246	49,361
Other	88,140	46,418	39,969	18,317	19,536	14,205
Mid-Continent:						
Arkoma Woodford	22,170	7,379	49,064	18,069	25,112	8,767
Other	53,819	25,629	22,320	16,846	181,952	111,231
Gulf Coast	9,561	1,989	3,200	2,443	5	3
Total	351,569	173,828	357,533	182,802	342,901	188,689

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Drilling Activity

During the three years ended December 31, 2007, we drilled exploratory and development wells as set forth in the table below:

	2007		2006		2005	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells:						
Oil	33	15.6	17	8.4	13	5.9
Natural gas	79	13.1	25	4.9	2	1.3
Dry	4	2.5	17	9.4	11	6.9
Total exploratory wells	116	31.2	59	22.7	26	14.1
Development wells:						
Oil	92	69.5	83	57.0	50	30.6
Natural gas	49	10.3	34	14.5	15	7.6
Dry	5	1.1	7	4.3	3	3.0
Total development wells	146	80.9	124	75.8	68	41.2
Total wells	262	112.1	183	98.5	94	55.3

As of December 31, 2007, there were 26 gross (12.7 net) development wells and 42 gross (19.9 net) exploratory wells in the process of drilling.

As of February 29, 2008, we operated 15 rigs on our properties and have plans to add additional rigs during the year. There can be no assurance, however, that additional rigs will be available to us at an attractive cost. See Risk Factors The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Summary of Oil and Natural Gas Properties and Projects

Rocky Mountain Region

Our properties in the Rocky Mountain region represented 87% of our PV-10 as of December 31, 2007. During the three months ended December 31, 2007, our average daily production from such properties was 22,365 net Bbls of oil and 13,409 net Mcf of natural gas. Our principal producing properties in this region are in the Red River units, the Bakken field and the Big Horn Basin.

Red River Units

Our Red River units represented 56% of our PV-10 in the Rocky Mountain region as of December 31, 2007 and 58% of our average daily Rocky Mountain region equivalent production for the three months ended December 31, 2007. The eight units comprising the Red River units are located along the Cedar Hills Anticline in North Dakota, South Dakota and Montana and produce oil and natural gas from the Red River B formation, a thin, continuous, dolomite formation at depths of 8,000 to 9,500 feet. Our Red River units comprise a portion of the Cedar Hills field, listed by the Energy Information Administration in 2006 as the 13th largest onshore, lower 48 field in the United States ranked by liquid proved reserves.

Cedar Hills Units. The Cedar Hills North unit (CHNU) is located in Bowman and Slope Counties, North Dakota. We drilled the initial horizontal well in the CHNU, the Ponderosa 1-15, in April 1995. As of December 31, 2007, we had drilled 185 horizontal wells within this 49,700-acre unit, with 113 producing wellbores and the remainder serving as injection wellbores. We operate and own a 98% working interest in the CHNU.

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The Cedar Hills West unit (CHWU), in Fallon County, Montana, is contiguous to the northern portion of CHNU. As of December 31, 2007, this 7,800-acre unit contained ten horizontal producing wells and five horizontal injection wells. We operate and own a 100% working interest in the CHWU.

In January 2003, we commenced enhanced recovery in the two Cedar Hills units, with HPAI used throughout most of the area and water injected generally along the boundary of the CHNU. Under HPAI, compressed air injected into a reservoir oxidizes residual oil and produces flue gases (primarily carbon dioxide and nitrogen) that mobilize and sweep the crude oil into producing wellbores. In response to the HPAI, water injection and increased density drilling operations, production from the Cedar Hills units increased to 10,869 net Boe per day in December 2007 from 2,185 net Boe per day in November 2003. As of December 31, 2007, the average density in the Cedar Hill units was approximately one producing wellbore per 467 acres. We currently plan to drill 56 new horizontal wellbores and 5 horizontal extensions of existing wellbores in the Cedar Hills units during the next two years, increasing the density of both the producing and injection wellbores. The reduced distance between wells will allow part of the field to be converted from air injection to water injection. This conversion will begin in 2008 and is forecast to lower operating expenses, as water is less costly to inject than air. In 2008, we plan to invest approximately $113 million drilling in the Cedar Hills units.

On August 22, 2007 the Hiland Partners, LP (Hiland) Badlands gas plant became operational for the processing and treatment of gas produced from the CHNU and CHWU and Medicine Pole Hills Unit. Under the terms of the November 8, 2005 contract we agree to deliver low pressure gas to Hiland for compression, treatment and processing. Nitrogen and carbon dioxide must be removed from the gas production associated with oil production from the units for the gas production to be marketable. Under the terms of the contract, we pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. During December 2007, we sold 5,322 net Mcf of natural gas per day.

Medicine Pole Hills Units. The Medicine Pole Hills units (MPHU) are approximately five miles east of the southern portion of the CHNU. We acquired the Medicine Pole Hills unit in 1995. At that time, the 9,600- acre unit consisted of 18 vertical producing wellbores and four injection wellbores under HPAI producing 525 net Bbls of oil per day. We have since drilled 40 horizontal wellbores extending production to the west with the formation of the 15,000-acre Medicine Pole Hills West unit and to the south, with the 11,500-acre Medicine Pole Hills South unit. All three units are under HPAI. We operate and own an average 77% working interest in the three units. Production from the units averaged 1,234 net Bbls of oil and 409 net Mcf of natural gas per day during December 2007. We are currently operating one rig and plan to drill 12 new horizontal wellbores and four horizontal extensions of existing wellbores during the next 18 months, increasing the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. In 2008, we plan to invest approximately $29.0 million for drilling in MPHU.

Buffalo Red River Units. Three contiguous Buffalo Red River units (Buffalo, West Buffalo and South Buffalo) are located in Harding County, South Dakota, approximately 21 miles south of the MPHU. When we purchased the units in 1995, there were 73 vertical producing wellbores and 38 injection wellbores under HPAI producing approximately 1,906 net Bbls of oil per day. We operate and own an average working interest of 95% in the 32,900 acres comprising the three units. From 2005 to 2008, we re-entered 42 existing vertical wells and drilled horizontal laterals to increase production and sweep efficiency from the three units. Production for the month of December 2007 was 1,945 net Bbls of oil per day compared to an average of 1,162 net Bbls of oil per day for the first half of 2005. We currently plan to drill 5 horizontal extensions of existing wellbores and 25 new horizontal wellbores in the Buffalo Red River units over the next two years. We believe these operations will increase production and sweep efficiency. In 2008, we plan to invest $23 million for drilling in the Buffalo Red River units.

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Bakken Field

Our properties within the Bakken field in Montana and North Dakota represented 28% of our PV-10 in the Rocky Mountain region as of December 31, 2007 and 35% of our average daily Rocky Mountain region equivalent production for the three months ended December 31, 2007. The Bakken formation or Bakken shale as it is often called has become one of the most actively drilled unconventional oil resource plays in the United States with approximately 54 rigs drilling in the play as of February 29, 2008, including 48 in North Dakota and 6 in Montana. The Bakken formation is a Devonian-age shale found within the Williston Basin underlying portions of North Dakota and Montana that contains three lithologic members including the upper shale, middle member and lower shale that combined range up to 130 feet thick. The upper and lower shales are highly organic, thermally mature and over pressured and act as both a source and reservoir for the oil. The middle member, which varies in composition from a silty dolomite, to shalely limestone or sand, also serves as a reservoir and locally is thought to be a critical component for commercial production. Recently, the Three Forks-Sanish formation found immediately under the Lower Bakken Shale has emerged as another potential reservoir that could add significant incremental reserves to the play. These reservoir rocks have inherently low porosity and permeability and depend on natural fracturing and artificial fracture stimulation to produce economically. Horizontal drilling and advanced fracture stimulation technologies have enabled commercial production from this historically non-commercial reservoir. Generally, the Bakken formation is found at vertical depths of 9,000 to 10,500 feet and drilled horizontally on 640 or 1,280-acre spacing with single, dual or triple leg horizontal laterals extending 4,500 to 9,000 feet into the formation. These wells are fracture stimulated to maximize recovery and economic returns. The fracture stimulation techniques vary but are evolving to a more common practice of mechanically diverted stimulations using un-cemented liners and packers which appears to improve rates and recoveries.

Montana Bakken. The Montana Bakken field is listed by the Energy Information Administration as the 15th largest onshore, lower 48 field in the United States ranked by liquid proved reserves. Since drilling our first well in August 2003, we have completed a total of 134 gross (84 net) wells in the field as of December 31, 2007. Our daily average production from these wells was approximately 6,334 net Bbls of oil and 4,814 net Mcf of natural gas during the month of December 2007. The field has been developed exclusively with horizontal drilling and has been substantially drilled on 640-acre spacing. During 2007 we completed 35 gross (25.9 net) wells as we continued to develop and expand the field. Two of these wells successfully demonstrated that development of the field on 320-acre spacing is warranted. These 2 gross (1.3 net) wells were assigned average estimated recoverable reserves of 468 gross MBoe, which exceeded our economic model of 300 MBoe per well. We also successfully demonstrated that 640-acre tri-lateral drilling was an effective technique to expand the economic limits of the field with the completion of 8 gross (6.2 net) tri-lateral wells which were assigned average estimated reserves consistent with our economic model of 250 MBoe per well.

As of December 31, 2007, we held 86,488 gross (64,536 net) undeveloped acres in the Richland County, Montana portion of the Bakken field. We currently have three operated rigs drilling in the field and plan to invest $48.0 million in the drilling of 17 gross (13 net) horizontal Bakken wells in the field during 2008.

North Dakota Bakken. Since drilling our first well in October, 2004, we have completed a total of 54 gross (21 net) horizontal wells in the North Dakota Bakken field as of December 31, 2007. Our daily average production from these 54 wells was approximately 1,351 net Bbls of oil and 820 net Mcf of natural gas during the month of December 2007. Our drilling to date has been primarily exploratory and step-out in nature to evaluate and define areas of economic production for further development on our acreage. As of December 31, 2007, we owned approximately 296,000 net acres preferentially located along the prolific Nesson anticline where fracturing in the Bakken is expected to be enhanced. We accelerated our drilling activity in the field during 2007, completing 38 gross (14.7 net) wells during the year. Twenty seven of these completed wells were located in the central and northern portions of our acreage and were assigned average estimated recoverable reserves of 335 gross MBoe per well, which is in line with our economic model of 315 MBoe per well. During the year, we modified our horizontal drilling and completion design and now drill primarily 1,280-acre spaced, single leg laterals utilizing uncemented liners and packers to mechanically divert the fracture stimulation.

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As of December 31, 2007, we held 553,516 gross (271,667 net) undeveloped acres in the North Dakota Bakken field. We currently have six drilling rigs in the field, three of which are operated by Conoco-Phillips through a joint venture. We plan to add three to five operated rigs to the play and invest approximately $105 million in the drilling of 74 gross (20 net) horizontal wells in the North Dakota Bakken field during 2008.

Haley Red River.

Our Haley Red River project is located approximately 12 miles northeast of our Buffalo Red River units located in Harding County, South Dakota. The producing reservoir is the same Red River B dolomite that produces in our Red River units. Here the dolomite occurs at a depth of approximately 9,000 feet and averages 4 to 6 feet thick. The dolomite is widely present and oil saturated and, as in our Red River units, must be drilled horizontally to produce at economic rates. Horizontal wells are typically drilled on 640-acre spacing as single leg laterals and completed open hole without stimulation. As of December 31, 2007 we have completed 4 gross (4 net) horizontal wells with initial rates of up to 419 Boe per well per day. Based on our economic model, we expect to recover approximately 250 MBoe per well. We owned approximately 58,000 net acres as of December 31, 2007 and continue to build acreage in the project. We plan to invest approximately $18 million drilling 9 gross (7.7 net) wells during 2008 in the Haley Red River project.

Big Horn Basin and Other Rockies

Our wells within the Big Horn Basin in northern Wyoming and other areas within the Rocky Mountain region represented 4% of our PV-10 in the Rocky Mountain Region as of December 31, 2007 and 4% of our average daily Rocky Mountain Region equivalent production for the three months ended December 31, 2007. During the three months ended December 31, 2007, we produced an average of 767 net Bbls of oil and 1,060 net Mcf of natural gas per day from our wells in the Big Horn Basin and other areas within the Rocky Mountain region. Our principal property in the Big Horn Basin, the Worland field, produces primarily from the Phosphoria formation. We also have several other projects ongoing in the Rockies including conventional 3D defined Red River and Lodgepole structures in North Dakota and Montana, horizontal Winnipegosis and Fryburg opportunities in North Dakota and the Lewis Shale and Fort Union in Wyoming. We plan to invest $9 million drilling 11 gross (5.1 net) wells in 2008.

Mid-Continent and Gulf Coast Region

Our properties in the Mid-Continent region represented 13% of our PV-10 as of December 31, 2007. During the three months ended December 31, 2007, our average daily production from such properties was 1,613 net Bbls of oil and 20,949 net Mcf of natural gas. Our principal producing properties in this region are located in the Anadarko and Arkoma Basins of Oklahoma, the Michigan Basin and the Illinois Basin.

Anadarko Basin

Our properties within the Anadarko Basin represent 40% of our PV-10 in the Mid-Continent Region as of December 31, 2007 and 52% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2007. Our wells within the Anadarko Basin produce from a variety of sands and carbonates in both stratigraphic and structural traps. In 2008, we plan to invest approximately $18 million in the drilling of 14 gross (10.5 net) wells in the Anadarko Basin.

Illinois Basin

Our properties within the Illinois Basin represent 30% of the PV-10 in the Mid-Continent Region as of December 31, 2007 and 21% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2007. Our wells within the Illinois Basin produce primarily crude oil from units comprised of shallow sand formations under water injection. In 2008, we plan to invest approximately $3 million in the drilling of 21 gross (20.6 net) wells in the Illinois Basin.

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Arkoma Woodford

The Arkoma Woodford play in Atoka, Coal, Hughes and Pittsburg Counties, Oklahoma has emerged into one of the most active unconventional gas resource plays in the country with 34 rigs drilling in the play as of February 29, 2008. We owned approximately 145,000 gross (44,000 net) acres in the Woodford play as of December 31, 2007. Since drilling our first well in February, 2006, we have completed a total of 132 gross (16.1 net) horizontal Woodford wells as of December 31, 2007. The majority of this drilling occurred in 2007 with 110 gross (14.8 net) horizontal wells completed during the year. These Arkoma Woodford wells represent 30% of the PV10 in the Mid-Continent Region as of December 31, 2007 and 26% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2007. Our drilling has been primarily focused on exploration and step-out drilling to secure leases and delineate areas of economic production for development. This drilling has been conducted primarily on 640-acre spacing but is expected to be ultimately drilled more densely. Recent testing by other operators in the play indicated it may be economic to drill the Woodford on 80-acre and possibly 40-acre spacing.

We plan to invest approximately $93 million in the drilling of 139 gross (19.9 net) horizontal wells in the Arkoma Woodford during 2008. We currently have four operated rigs in the play and plan to add two more rigs by mid-year. Most of our operated drilling activity in 2008 will focus on development and step-out opportunities.

Michigan Trenton-Black River

Our Trenton-Black River project in and around Hillsdale County, Michigan continues to produce excellent results. Guided by innovative 3D seismic techniques, we have experienced 100% success completing 3 gross (2.5 net) operated wells in the project. Our initial discovery well, the McArthur 1-36 (83% WI) has been assigned gross proved reserves of 824,000 barrels of crude oil equivalent. Our second well, the Anspaugh 1-1 (83% WI) encountered similar type pay and was flow testing at a rate of approximately 200 Bopd on March 3, 2008. Our third well, the Wessel 1-6 (83% WI) was flow testing at a rate of approximately 200 Bopd on March 3, 2008. Testing will continue on the Anspaugh 1-1 and Wessel 1-6 to establish reservoir characteristics and estimated reserves. We have also participated in 2 gross (0.6 net) non-operated Trenton-Black River tests. The Clark 1-36 (21%WI) is testing very low volumes of oil. The Young 10-34 (42%WI) encountered encouraging shows while drilling and is currently waiting on completion. We own approximately 29,000 gross (23,000 net) acres in the play and have shot, processed and interpreted 11 square miles of 3D seismic on the acreage so far. We are currently permitting 5 additional wells and will begin acquisition of 20 square miles of new 3D data in March with plans to acquire additional data later this year.

Other Mid-Continent

During 2007 our geoscientists identified two new potential unconventional resource opportunities in the Mid-Continent region. Details of these opportunities have not been disclosed to minimize competition as we are in the process of acquiring leases. As of December 31, 2007 we had acquired 17,000 net acres. We plan to invest approximately $20 million drilling 19 gross (7.1 net) wells on these and other emerging opportunities in the Mid-Continent region in 2008.

Gulf Coast

During the three months ended December 31, 2007, our average daily production from our Gulf Coast properties was 330 net Bbls of oil and 2,004 net Mcf of natural gas. Our principal producing properties in this region are located in South Texas and Louisiana. In 2008, we plan to invest approximately $18.0 million in the drilling of 9 gross (5.4 net) wells in the Texas and Louisiana Gulf Coast.

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Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the years ended December 31, 2007, 2006 and 2005:

	Year ended December 31,		
	2007	2006	2005
Net production volumes:			
Oil (MBbls)(1)	8,699	7,480	5,708
Natural gas (MMcf)	11,534	9,225	9,006
Oil equivalents (MBoe)	10,621	9,018	7,209
Average prices(1) :			
Oil ($/Bbl)	$ 63.55	$ 55.30	$ 52.45
Natural gas ($/Mcf)	5.87	6.08	6.93
Oil equivalents ($/Boe)	58.32	52.09	50.19
Costs and expenses(1):			
Production expense ($/Boe)	$ 7.35	$ 6.99	$ 7.32
Production tax ($/Boe)	3.13	2.48	2.22
General and administrative ($/Boe)	3.15	3.45	4.34
DD&A expense ($/Boe)	9.00	7.27	6.91

(1) Oil sales volumes are 221 MBbls and 21 MBbls less than oil production volumes for the years ended December 31, 2007 and 2006, respectively, due to temporary storage and pipeline line fill. Average prices and per unit costs have been calculated using sales volumes.

The following table sets forth information regarding our average daily production during the fourth quarter of 2007:

	Fourth Quarter 2007		
	Oil (Bbls)	Gas (Mcf)	Total (Boe)
Rockies:			
Red River units	13,520	5,121	14,374
Bakken field			
Montana Bakken	6,433	4,866	7,244
North Dakota Bakken	1,263	715	1,382
Other	1,149	2,707	1,600
Mid-Continent:			
Arkoma Woodford		8,029	1,338
Other	1,614	12,920	3,767
Gulf Coast	330	2,004	664
Total	24,309	36,362	30,369

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Productive Wells

The following table presents the total gross and net productive wells by region and by oil or gas completion as of December 31, 2007:

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units	249	226.6	2	2.0	251	228.6
Bakken field						
Montana Bakken	130	81.2	3	2.0	133	83.2
North Dakota Bakken	49	19.5	3	1.0	52	20.5
Other	254	226.4	4	1.3	258	227.7
Mid-Continent:						
Arkoma Woodford	0	0.0	129	16.2	129	16.2
Other	736	589.3	231	123.8	967	713.1
Gulf Coast	4	3.0	28	13.7	32	16.7
Total	1,422	1146.0	400	160.0	1,822	1,306.0

Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells. As of December 31, 2007, we owned interests in no wells containing multiple completions.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

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 transported by truck to storage facilities. During the fourth quarter of 2007, we were unable to market some of our Rocky Mountain area crude at a price acceptable to us. This resulted in an increase in our crude oil inventory of 125 MBbls. The price we were offered was adversely affected by seasonal demand. We have temporarily shipped some of our Rocky Mountain crude by railcar to help alleviate this situation. We were able to sell the majority of this oil in January and February 2008. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, see Risk factors Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

For the year ended December 31, 2007, oil sales to Tidal Energy Marketing (U.S.) L.L.C., Marathon Oil Company and Suncor Energy accounted for 20%, 14% and 10%, respectively, of our total revenue. No other purchasers accounted for more than 10% of our total oil and gas sales. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil purchasers in our producing regions.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Our competitors vary within the regions in which we operate, and some of our competitors may 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. In addition, shortages or the high cost of drilling rigs could delay or adversely affect our development and exploration operations. 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 of the Oil and Natural Gas Industry

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 and access regulation. The Federal Energy Regulatory Commission, or 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. 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 similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorating 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 Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily 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 and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. 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 a series of orders to implement its open access policies. As a result, 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.

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.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation is also 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. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

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

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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.

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, Health and Safety Regulation

General. Our operations are subject to stringent and complex federal, state, local and provincial laws and regulations governing environmental protection, health and safety, including the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas including areas containing endangered animal species; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on our operating costs.

Some of the existing environmental, health and safety laws and regulations to which our business operations are subject include, among others, (i) regulations by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act and analogous state laws that regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) the Clean Air Act and comparable state and local requirements, which may result in the gradual imposition of certain pollution control requirements with respect to air emissions from the operations of the Company; (iv) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States; (v) the Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws which impose restrictions and strict controls with respect to the discharge of pollutants, including oil and other substances generated by our operations, into waters of the United States or state waters; (vi) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; (vii) the Safe Drinking Water Act and analogous state laws which impose requirements relating to our underground injection activities; (viii) the National Environmental Policy Act which requires federal agencies, including the Department of Interior, to evaluate major agency actions that have the potential to significantly impact the environment; (ix) the federal Occupational Safety and Health Act and comparable state statutes which requires that we organize and/or disclose information about hazardous materials stored, used or produced in our operations and; (x) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material.

We have incurred in the past, and expect to incur in the future, capital and other expenditures related to environmental compliance. Such expenditures, however, are included within our overall capital and operating

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budgets and are not separately itemized. Although we believe that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operations.

Employees

As of December 31, 2007, we employed 332 people, including 181 employees in drilling and production, 47 in financial and accounting, 33 in land, 21 in exploration, 11 in reservoir engineering, 28 in administrative and 11 in information technology. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Initial Public Offering

On May 14, 2007, the Company completed its initial public offering. In conjunction therewith, the Company affected an 11 for 1 stock split by means of a stock dividend. All prior period share and per share information contained in this report have been retroactively restated to give effect to the stock split. On May 14, 2007, the Company amended its certificate of incorporation to, among other things, increase the number of authorized preferred shares to 25 million and common shares to 500 million. Prior to completion of the public offering, the Company was a subchapter S corporation and income taxes were payable by its shareholders. In connection with the public offering, the Company converted to a subchapter C corporation and recorded a charge to earnings in the second quarter of $198.4 million to recognize deferred taxes at May 14, 2007. Thereafter, the Company has provided for income taxes on income. See *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies Pro forma information (unaudited) and Income taxes and Note 11. Shareholders Equity* for a complete discussion of the accounting for the various transactions resulting from the initial public offering and of the pro forma information presented.

Company Contact Information

Our corporate internet web site is *www.contres.com.* Through the investor relations section of our website, we make available our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after the report is filed or furnished with the Securities and Exchange Commission. Information contained at our website is not incorporated by reference into this report and you should not consider information contained at our website as part of this report.

We file periodic reports and proxy statements with the Securities and Exchange Commission (SEC). The public may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of this site is http://www.sec.gov.

Our principal executive offices are located at 302 N. Independence, Enid, Oklahoma 73701, and our telephone number at that address is (580) 233-8955.

Item 1A. Risk Factors

You should carefully consider each of the risks described below, together with all of the other information contained in this report, before deciding to invest in shares of our common stock. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading price of your shares could decline and you may lose all or part of your investment.

Risks Relating to the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

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. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices will reduce our cash flows and borrowing ability. See Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices would render uneconomic a significant portion of our exploitation projects. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

In addition, because our producing properties are geographically concentrated in the Rocky Mountain region, we are vulnerable to fluctuations in pricing in that area. In particular, 81% of our production during the fourth quarter of 2007 was from the Rocky Mountain region. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, transportation capacity constraints, curtailment of production or interruption of transportation of oil produced from the wells in these areas. Such factors can cause significant fluctuation in our realized oil and natural gas prices. For example, the company-wide difference between the average NYMEX oil price and our average realized oil price for the year ended December 31, 2007 was $8.85 per Bbl, whereas the company-wide difference between the NYMEX oil price and our realized oil price for the year ended December 31, 2006 was $11.04 per Bbl.

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

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control; including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. Our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See Item 1. Business Proved Reserves for information about our estimated oil and natural gas reserves and the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2007.

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

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

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You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If oil prices decline by $1.00 per Bbl, then our PV-10 as of December 31, 2007 would decrease approximately $50 million. If natural gas prices decline by $0.10 per Mcf, then our PV-10 as of December 31, 2007 would decrease approximately $9 million.

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

One of our business strategies is to commercially develop unconventional oil and natural gas resource plays using enhanced recovery technologies. For example, we inject water and high-pressure air into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and natural gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected.

Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Our cash flow used in investing activities was $486.4 million related to capital and exploration expenditures in 2007. Our budgeted capital expenditures for 2008 are expected to increase to approximately $616.0 million. To date, these capital expenditures have been financed with cash generated by operations and through borrowings from banks and, prior to our initial public offering, from our principal shareholder. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional debt may require that a portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of your common stock.

Our cash flow from operations and access to capital are subject to a number of variables, including:

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

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

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

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

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

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

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

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations; we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

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

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines in connection with our high-pressure air injection operations;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

injury or loss of life;

- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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

Prospects that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our result of operations and financial condition. In this report, we describe some of our current prospects and our plans to explore those prospects. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

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

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. The North Dakota Bakken Shale and Arkoma Woodford projects comprise the majority of these drilling locations. Due to limited production history on the relatively few number of wells drilled in these projects, we are unable to predict with certainty the quantity of future production from wells to be drilled in these projects. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2007, we had 173,828, 182,802 and 188,689 net acres expiring in 2008, 2009 and 2010, respectively. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil

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

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

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

We are subject to complex federal, state, local, provincial and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our oil and natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and provincial governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state, local and provincial laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. See Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect us.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from our operations.

New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

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 for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our

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competitors possess and employ financial, technical and personnel resources substantially greater than ours. 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. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Harold G. Hamm, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Terrorist attacks aimed at our energy operations could adversely affect our business.

The continued threat of terrorism and the impact of military and other government action have led and may lead to further increased volatility in prices for oil and natural gas and could affect these commodity markets or financial markets used by us. In addition, the U.S. government has issued warnings that energy assets may be a future target of terrorist organizations. These developments have subjected our oil and natural gas operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other energy companies, could have a material adverse effect on our business.

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

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

Our credit facility contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our credit facility includes certain covenants that, among other things, restrict:

- our investments, loans and advances and the paying of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the credit facility and certain permitted liens;
- mergers, consolidations and sales of all or substantial part of our business or properties;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;

the sale of assets; and

our capital expenditures.

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Our credit facility requires us to maintain certain financial ratios, such as leverage ratios. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our credit facility, in which case, depending on the actions taken by the lenders there under or their successors or assignees, such lenders could elect to declare all amounts borrowed under our credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

Increases in interest rates could adversely affect our business.

We are exposed to changes in interest rates as a result of borrowings outstanding under our credit facility. At February 29, 2008, our outstanding borrowings were $222.0 million and the impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $2.2 million and a $1.4 million decrease in our net income.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The two largest purchasers of our oil and natural gas during the twelve months ended December 31, 2007 accounted for 20% and 14% of our total oil and natural gas sales revenues. We do not require our customers to post collateral. The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we on occasion, enter into derivative instruments for a portion of our oil and/or natural gas production, including collars and price-fix swaps. In July 2007, we entered into fixed price swaps covering 10,000 barrels of oil per day for August 2007 through April 2008 at a price of $72.90 per barrel. We have not designated any of our derivative instruments as hedges for accounting purposes and will record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments will be recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments. Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas.

We may be subject to risks in connection with acquisitions.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;

- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost effective manner.

As a new public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the New York Stock Exchange (NYSE) with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, document, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities; and
- establish an investor relations function.

In addition, we also expect that being a public company subject to these rules and regulations will require us to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, and qualified executive officers. As a result, compliance with the requirements of the Sarbanes-Oxley Act could have a material adverse effect on our business.

Our Chairman and Chief Executive Officer own approximately 72.8% of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our company.

As of February 29, 2008, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owns 123,140,608 shares of our outstanding common representing approximately 72.8% of our outstanding common stock. As a result, Mr. Hamm will continue to be our controlling shareholder and will continue to be able to

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control the election of our directors, determine our corporate and management policies and determine, without the consent of our other shareholders, the outcome of certain corporate transactions or other matters submitted to our shareholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. As controlling shareholder, Mr. Hamm could cause, delay or prevent a change of control of our company. The interests of Mr. Hamm may not coincide with the interests of other holders of our common stock.

Several affiliated companies controlled by Mr. Hamm provide oilfield, gathering and processing, marketing and other services to us. We expect these transactions will continue in the future and may result in conflicts of interest between Mr. Hamm s affiliated companies and us. We can provide no assurance that any such conflicts will be resolved in our favor.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2007.

Item 2. Properties

The information required by Item 2 is contained in Item 1. Business Oil and Gas Operations.

Item 3. Legal Proceedings

We are not a party to any material pending legal proceedings, other than ordinary course litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding will not have a material adverse effect on our financial condition or results of operations.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2007.

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Part II

Item 5. Market for Registrant s Common Equity and Related Shareholder Matters

Our common stock is listed on the New York Stock Exchange and trades under the symbol CLR. The following table sets forth quarterly high and low sales prices since May 14, 2007, when we became a publicly traded company, and cash dividends declared for each quarter of the previous two years.

	2007				2006			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
High	$	$ 16.40	$ 18.97	$ 27.62	$	$	$	$
Low		14.00	14.11	18.05				
Cash Dividend	0.12	0.21			0.38		0.17	

We declared cash dividends to our shareholders of record for tax purposes and, subject to forfeiture, to holders of unvested restricted stock during such time as we were a subchapter S corporation. In connection with the completion of our offering on May 14, 2007, we converted from a subchapter S corporation to a subchapter C corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. As of February 29, 2008, the number of record holders of our common stock was 35. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 12,500. On February 29, 2008, the last reported sales price of our Common Stock, as reported on the NYSE, was $28.08 per share.

The following table summarizes our purchases of our common stock during the fourth quarter of 2007:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs
October	65,309	$ 20.96		
November	48,816	$ 22.44		
December	51,928	$ 24.55		
Total	166,053	$ 22.52		

All shares purchased above represent shares issued pursuant to stock option exercises or restricted stock grants that were surrendered to cover taxes required to be withheld. The Company paid the amounts above to the Internal Revenue Service for the required withholding. See *Notes to Consolidated Financial Statements Note 12. Stock Compensation.*

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Performance Graph

The performance graph shown below is being furnished pursuant to applicable rules of the SEC. As required by these rules, the performance graph was prepared based upon the following assumptions:

$100 was invested in our common stock at its initial public offering price of $15 per share and invested in the S&P 500 Index and our peer group on May 14, 2007 at the closing price on such date;

investment in our peer group was weighted based on the stock price of each individual company within the peer group at the beginning of the period; and

dividends were reinvested on the relevant payment dates.

Our peer group is comprised of Bill Barrett Corporation, Denbury Resources, Inc., Encore Acquisition Company, Quicksilver Resources, Inc., Range Resources Corp., Southwestern Energy Company and St. Mary Land and Exploration Company. We selected these companies because they are publicly traded exploration and production companies similar in size and operations to us.

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Item 6. Selected Financial Data

This section presents our selected historical and pro forma consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements.

The following historical consolidated financial data, as it relates to each of the fiscal years ended December 31, 2003 through 2007, has been derived from our audited historical consolidated financial statements for such periods. You should read the following selected historical consolidated financial data in connection with Management s Discussion and Analysis of Financial Condition and Results of Operation and our historical consolidated financial statements and related notes included elsewhere in this report. The selected historical consolidated results are not necessarily indicative of results to be expected in future periods.

		YEAR ENDED DECEMBER 31,			
(Dollars in thousands, except per share data)	**2007**	**2006**	**2005**	**2004**	**2003**
Statement of Income:					
Oil and natural gas sales[1]	$ 606,514	$ 468,602	$ 361,833	$ 181,435	$ 138,948
Derivative losses[1]	(44,869)				
Total revenues	582,215	483,652	375,764	418,910	317,609
Income (loss) from continuing operations	28,580	253,088	194,307	26,816	(768)
Net Income	28,580	253,088	194,307	27,864	2,340
Basic earnings per share:					
From continuing operations	$ 0.17	$ 1.60	$ 1.23	$ 0.18	$
Net income per share	$ 0.17	$ 1.60	$ 1.23	$ 0.18	$ 0.01
Shares used in basic earnings per share	164,059	158,114	158,059	158,059	158,059
Diluted earnings per share:					
From continuing operations	$ 0.17	$ 1.59	$ 1.22	$ 0.18	$
Net income per share	$ 0.17	$ 1.59	$ 1.22	$ 0.18	$ 0.01
Shares used in diluted earnings per share	165,422	159,665	159,307	159,236	158,059
Pro forma C-corporation[2]					
Pro forma income (loss) from continuing operations	$ 184,002	$ 156,833	$ 121,177	$ 16,626	$ (476)
Pro forma net income	184,002	156,833	121,177	17,276	1,451
Pro forma basic earnings per share	1.12	0.97	0.77	0.11	0.01
Pro forma diluted earnings per share	1.11	0.96	0.76	0.11	0.01
Production[3]					
Oil (MBbl)	8,699	7,480	5,708	3,688	3,463
Gas (MMcf)	11,534	9,225	9,006	8,794	10,751
Oil equivalent (MBoe)	10,621	9,018	7,209	5,154	5,255
Average sales prices[4]					
Oil ($/Bbl)	$ 63.55	$ 55.30	$ 52.45	$ 37.12	$ 25.98
Gas ($/Mcf)	5.87	6.08	6.93	5.06	4.55
Oil equivalent ($/Boe)	58.32	52.09	50.19	35.20	26.44
Average costs per Boe[5]					
Production expense	$ 7.35	$ 6.99	$ 7.32	$ 8.49	$ 7.16
Production tax	3.13	2.48	2.22	2.39	1.95
Depreciation, depletion, amortization and accretion	9.00	7.27	6.91	7.49	8.28
General and administrative	3.15	3.45	4.34	2.41	2.13
Proved reserves					
Oil (MBbl)	104,145	98,038	98,645	80,602	73,000
Gas (MMcf)	182,819	121,865	108,118	60,620	67,096
Oil equivalent (MBoe)	134,615	118,349	116,665	90,705	84,182
Other financial data:					
Cash dividends per share	$ 0.33	$ 0.55	$ 0.01	$ 0.09	$
EBITDAX[6]	469,885	372,115	285,344	116,498	88,750
Net cash provided by operations	390,648	417,041	265,265	93,854	65,246
Net cash used in investing	(483,498)	(324,523)	(133,716)	(72,992)	(108,791)
Net cash provided by (used in) financing	94,568	(91,451)	(141,467)	(7,245)	43,302
Capital expenditures	525,677	326,579	144,800	94,307	114,145
Balance sheet data at December 31:					

Total assets	$ 1,365,173	$ 858,929	$ 600,234	$ 504,951	$ 484,988
Long-term debt, including current maturities	165,000	140,000	143,000	290,522	290,920
Shareholders equity	623,132	490,461	324,730	130,385	116,932

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(1) Oil and natural gas sales for the years ended December 31, 2004 and 2003 are shown net of derivative loss accounted for as hedges of $6.4 million and $10.1 million, respectively. Derivative losses in 2007 were not accounted for as hedges and therefore are shown separately.
(2) Pro forma adjustments are reflected to provide for income taxes in accordance with SFAS No. 109 as if we had been a subchapter C corporation for all periods presented. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for all periods.
(3) For the years 2007 and 2006, oil sales volumes were 221 MBbls and 21 MBbls less than oil production volumes, respectively.
(4) Average sales prices for the years 2004 and 2003 are net of hedges. The price without hedges for 2004 was $38.85 per barrel of oil and $36.45 per barrel of oil equivalent and the price without hedges for 2003 was $28.88 per barrel of oil and $28.35 per barrel of oil equivalent.
(5) Average costs per Boe have been computed using sales volumes.
(6) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains or losses and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2007 and 2006, this ratio was approximately 0.4 to 1. The following table represents a reconciliation of our net income to EBITDAX:

	Year ended December 31,				
	2007	2006	2005	2004	2003
			(in thousands)		
Net Income	$ 28,580	$ 253,088	$ 194,307	$ 27,864	$ 2,340
Unrealized derivative loss	26,703				
Interest expense	12,939	11,310	14,220	23,617	19,761
Provision (benefit) for income taxes	268,197	(132)	1,139		
Depreciation, depletion, amortization and accretion	93,632	65,428	49,802	38,627	40,256
Property impairments	17,879	11,751	6,930	11,747	8,975
Exploration expense	9,163	19,738	5,231	12,633	17,221
Equity compensation	12,792	10,932	13,715	2,010	197
EBITDAX	$ 469,885	$ 372,115	$ 285,344	$ 116,498	$ 88,750

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

The following discussion should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this report.

Overview

We are engaged in oil and natural gas exploration and exploitation activities in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. Crude oil comprised 77% of our 134.6 MMBoe of estimated proved reserves as of December 31, 2007 and 82% of our 10,621 MBoe of production for the year then ended. We seek to operate wells in which we own an interest, and we operated wells that accounted for 93% of our PV-10 and 79% of our 1,822 gross wells as of December 31, 2007. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Our business strategy has focused on reserve and production growth through exploration and development. For the three-year period ended December 31, 2007, we added 66,087 MBoe of proved reserves through extensions and discoveries, compared to 561 MBoe added through purchases. During this period, our production increased from 7,209 MBoe in 2005 to 10,621 MBoe in 2007. An aspect of our business strategy has been to acquire large undeveloped acreage positions in new or developing resource plays. As of December 31, 2007, we held approximately 1,359,098 gross (733,132 net) undeveloped acres, including 336,000 net acres in the Bakken field in Montana and North Dakota and 70,554 net acres in the Arkoma Woodford and Lewis Shale projects. As an early entrant in new or emerging plays, we expect to acquire undeveloped acreage at a lower cost than those of later entrants into a developing play.

In the year ended December 31, 2007, our oil and gas production increased to 10,621 MBoe (29,099 Boe per day), up 18% from the year ended December 31, 2006. The increase in 2007 production primarily resulted from an increase in production from our Red River units, Bakken field and Arkoma Woodford. Oil and natural gas revenues for the year 2007 increased by 29% to $606.5 million due to increases in volumes and price. Our realized price per Boe increased $6.22 to $58.31 for the year 2007 compared to the year 2006. While we experienced increases in production expense and production tax of a combined total of $23.9 million, or 28%, our increase in combined per unit cost was only 11%, or $1.01 per Boe, due to the increase in sales volumes of 1,405 MBoe, or 16%. Oil sales volumes were 221 MBbls less than oil production for the year ended December 31, 2007 and 21 MBbls less for the same period in 2006, due to an increase in crude oil inventory for pipeline line fill and temporarily stored barrels. Our cash flow from operating activities for the year ended December 31, 2007, was $390.6 million, a decrease of $26.4 million from $417.0 million provided by our operating activities during the comparable 2006 period. The decrease in operating cash flows was mainly due to changes in working capital items including an increase in accounts receivables and an increase in crude oil inventory. During the year ended December 31, 2007, we invested $525.7 million (inclusive of non-cash accruals of $36.4 million) in our capital program primarily in the Red River units, the Bakken field and the Arkoma Woodford play.

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How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance. Among these measures are (1) volumes of oil and natural gas produced, (2) oil and natural gas prices realized, (3) per unit operating and administrative costs and (4) EBITDAX. The following table contains financial and operational highlights for each of the three years ended December 31, 2007.

	Year Ended December 31,		
	2007	2006	2005
Average daily production:			
Oil (Bopd)	23,832	20,494	15,639
Natural gas (Mcfpd)	31,599	25,274	24,675
Oil equivalents (Boepd)	29,099	24,706	19,752
Average prices:(1)			
Oil ($/Bbl)	$ 63.55	$ 55.30	$ 52.45
Natural gas ($/Mcf)	5.87	6.08	6.93
Oil equivalents ($/Boe)	58.31	52.09	50.19
Production expense ($/Boe)(1)	7.35	6.99	7.32
General and administrative expense ($/Boe)(1)	3.15	3.45	4.34
EBITDAX (in thousands)(2)	469,885	372,115	285,344
Net income (in thousands)(3)	28,580	253,088	194,307
Pro forma net income (in thousands)(4)	184,002	156,833	121,177
Diluted net income per share	0.17	1.59	1.22
Pro forma diluted net income per share(4)	1.11	0.96	0.76

(1) Oil sales volumes were 221 MBbls less than oil production for the year ended December 31, 2007 and 21 MBbls less than oil production for the year ended December 31, 2006 due to temporary storage and pipeline line fill. Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

(2) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains and losses and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). A reconciliation of net income to EBITDAX is provided in Item 6. Selected Financial Data.

(3) Prior to the public offering, we were a subchapter S corporation and income taxes were payable by our shareholders and as a result, there was a minimal provision for income taxes for the periods ended December 31, 2005 and 2006. See *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies Income taxes*. In connection with the public offering, we converted to a subchapter C corporation and recorded a charge to earnings in the second quarter of 2007 of $198.4 million to recognize deferred taxes relating to the temporary differences that existed at May 14, 2007, the date we converted to a subchapter C corporation.

(4) Pro forma adjustments are reflected to provide for income taxes in accordance with SFAS No. 109 as if we had been a subchapter C corporation for all periods presented. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for all periods.

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Results of Operation

The following table presents selected financial and operating information for each of the three years ended December 31, 2007:

(in thousands, except volume price data)	December 31, 2007	2006	2005
Oil and natural gas sales	$ 606,514	$ 468,602	$ 361,833
Derivatives	(44,869)		
Total revenues	582,215	483,652	375,764
Operating costs and expenses	274,248	221,128	166,965
Other expense	11,190	9,568	13,353
Net income, before income taxes	296,777	252,956	195,446
Provision (benefit) for income taxes	268,197	(132)	1,139
Net income	$ 28,580	$ 253,088	$ 194,307
Production Volumes:			
Oil (MBbl)	8,699	7,480	5,708
Natural gas (MMcf)	11,534	9,225	9,006
Oil equivalents (MBoe)	10,621	9,018	7,209
Sales Volumes:			
Oil (MBbl)	8,478	7,459	5,708
Natural gas (MMcf)	11,534	9,225	9,006
Oil equivalents (MBoe)	10,400	8,997	7,209
Average Prices:[1]			
Oil ($/Bbl)	$ 63.55	$ 55.30	$ 52.45
Natural gas ($/Mcf)	$ 5.87	$ 6.08	$ 6.93
Oil equivalents ($/Boe)	$ 58.32	$ 52.09	$ 50.19

(1) Oil sales volumes are 221 MBbls and 21 MBbls less than oil production volumes for the years ended 2007 and 2006, respectively, due to temporary storage and pipeline linefill.

Year ended December 31, 2007 compared to the year ended December 31, 2006

Production

The following tables reflect our production by product and region for the periods presented.

	Year Ended December 31, 2007		2006		Volume	Percent
	Volume	Percent	Volume	Percent	increase	increase
Oil (MBbl)[1]	8,699	82%	7,480	83%	1,219	16%
Natural Gas (MMcf)	11,534	18%	9,225	17%	2,309	25%
Total (MBoe)	10,621	100%	9,018	100%	1,603	18%

	Year Ended December 31, 2007		2006		Volume increase	Percent increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
Rocky Mountain[1]	8,619	81%	7,159	79%	1,460	20%
Mid-Continent	1,794	17%	1,497	17%	297	20%

Gulf Coast	208	2%	362	4%	(154)	(43)%
Total (MBoe)	10,621	100%	9,018	100%	1,603	18%

(1) Oil sales volumes are 221 MBbls and 21 MBbls less than oil production volumes for the years ended 2007 and 2006, respectively, due to temporary storage and pipeline linefill.

Oil production volumes increased 16% during the year ended December 31, 2007 in comparison to the year ended December 31, 2006. Production increases in the Red River units contributed incremental volumes in excess of 2006 levels of 849 MBbls, and the Bakken field contributed 426 MBbls of incremental production. Initial production commenced in the Bakken field in August 2003 and has increased thereafter, as we have continued exploration and development activities within the Montana and North Dakota portions of the field. Favorable results from our enhanced recovery program and increased density drilling have been the primary contributors to production growth in the Red River units. Gas volumes increased 2,309 MMcf, or 25%, during the year ended December 31, 2007 compared to 2006. The majority of the increase, 1,833 MMcf, was from the Mid-Continent region due to the results of our exploration efforts in the Arkoma Woodford. The Rocky Mountain gas production was up 1,227 MMcf for the year ended December 31, 2007 compared to 2006. The new Hiland Partners Badlands Plant became operational in late August 2007. Through December 31, 2007, we sold 672 MMcf of gas from the Red River units through the new plant. We have invested a minimal amount of capital in our Gulf Coast region resulting in a decline in production in this area of 751 MMcf for the year ended December 31, 2007 compared to 2006.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the year ended December 31, 2007 were $606.5 million, a 29% increase from sales of $468.6 million for 2006. Our sales volumes increased 1,403 MBoe or 16% over the 2006 volumes due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe increased $6.22 to $58.32 for the year ended December 31, 2007 from $52.09 for the year ended December 31, 2006. During 2007, the differential between NYMEX calendar month average crude oil prices and our realized crude oil prices narrowed. The differential per barrel for the year ended December 31, 2007 was $8.85 compared to $11.04 for 2006. Factors contributing to the higher differentials in 2006 included Canadian oil imports, increases in production in the Rocky Mountain region, coupled with downstream transportation capacity constraints, refinery downtime in the Rocky Mountain region, and reduced seasonal demand for gasoline. Crude oil differentials were better during 2007 due to additional transportation capacity and efforts by us to move crude oil to more favorable markets.

During the fourth quarter of 2007, we elected not to sell some of our Rocky Mountain area crude oil as price differentials were unacceptable to us and we expected the differentials to improve in early 2008. This resulted in an increase in our crude oil inventory of 125,000 barrels. The price we were offered was adversely affected by seasonal demand. In the fourth quarter of 2007, we shipped some of our Rocky Mountain area crude by railcar to help alleviate this situation. We were able to sell the majority of this oil at improved differentials during January and February 2008.

Derivatives. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we will receive a fixed-price of $72.90 per barrel and will pay to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we mark our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognize the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of income. During the year ended December 31, 2007, we had realized losses on derivatives of $18.2 million and unrealized losses on derivatives of $26.7 million.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil, or reclaimed oil. We sold high-pressure air from our Red River units to a third party and recorded revenues of $3.1 million for the years ended December 31, 2007 and 2006. Prices for reclaimed oil sold from our central treating unit were higher for the year ended December 31, 2007 than the comparable 2006 period, and the number of barrels sold increased

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approximately 68,000 barrels which increased reclaimed oil income by $5.5 million contributing to an overall increase in oil and gas service operations revenue of $5.5 million for the year ended December 31, 2007. Associated oil and natural gas service operations expenses increased $4.5 million to $12.7 million during the year ended December 31, 2007 from $8.2 million during the year ended December 31, 2006 due mainly to an increase in additional barrels treated in 2007 and to an increase of $5.71 per barrel in the costs of purchasing and treating oil for resale compared to the same period in 2006.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $13.6 million, or 22% during the year ended December 31, 2007 to $76.5 million from $62.9 million during the year ended December 31, 2006. The increase in production expense is commensurate with our increase in production of 18% which is a direct result of new wells being drilled. Additionally, we have experienced a slight increase in service and energy costs. During the year ended December 31, 2007, we participated in the completion of 262 gross (112.1 net) wells. Production expense per Boe increased to $7.35 per Boe for the year ended December 31, 2007 from $6.99 per Boe for the year ended December 31, 2006.

Production taxes increased $10.2 million, or 46% during the year ended December 31, 2007 compared to the year ended December 31, 2006 primarily as a result of higher revenues resulting from increased sales volumes and prices. The majority of the production tax increase was in the Rocky Mountain region due to an increase of 1,261 MBoe sold in the year ended December 31, 2007 compared to the year ended December 31, 2006. Production tax as a percentage of oil and natural gas sales was 5.4% for the year ended December 31, 2007 compared to 4.8% for the year ended December 31, 2006. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, new horizontal wells qualify for a tax incentive and are taxed at 0.76% during the first 18 months of production. After the 18 month incentive period expires, the tax rate increases to 9.26%. During the year ended December 31, 2007, 32 wells had reached the end of the 18 month incentive period and the tax rate increased from 0.76% to 9.26%. Our overall rate is expected to increase as production tax incentives received for horizontal wells in Montana reach the end of the 18 month incentive period. We are also receiving a 6% tax incentive on horizontal wells drilled in the Arkoma Woodford play in Oklahoma that continues for up to four years or until the revenue from such well exceeds the cost to drill and complete. In North Dakota, we are receiving a 4.5% tax credit on horizontal Bakken wells spud after July 1, 2007 and completed before June 30, 2008. The incentive expires on the earliest to occur of 75,000 barrels of production or eighteen months.

On a unit of sales basis, production expense and production taxes were as follows:

	Year Ended December 31,		Percent
	2007	**2006**	**Increase**
Production expense ($/Boe)	$ 7.35	$ 6.99	5%
Production tax ($/Boe)	3.13	2.48	26%
Production expense and tax ($/Boe)	$ 10.48	$ 9.47	11%

Exploration Expense. Exploration expense consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses decreased $10.6 million in the year ended December 31, 2007 to $9.2 million due primarily to a decrease in dry hole expense of $9.8 million and a decrease in seismic expense of $0.9 million. The majority of the dry hole costs were in the Mid-Continent region in the 2006 period and in the Mid-Continent and Rocky Mountain regions in the same period in 2007. Dry hole costs were down in 2007 even though exploratory capital expenditures increased by approximately 144% as a result of more successful exploration activities.

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Depreciation, Depletion, Amortization and Accretion (DD&A.) Total DD&A increased $28.2 million in 2007 primarily due to an increase in oil and gas DD&A of $27.9 million as a result of increased production and additional properties being added through our drilling program. The DD&A rate for the year ended December 31, 2007 was $9.00 per Boe, including $8.63 per Boe on oil and gas properties and $0.37 per Boe for other equipment and asset retirement obligation accretion, compared to $7.27 per Boe, including $6.91 per Boe for oil and gas properties and $0.36 per Boe for other equipment and asset retirement obligation accretion, for the same period in 2006. The increase in the oil and gas DD&A rate reflects the additional costs incurred to develop proved undeveloped reserves and the higher costs of drilling and completing wells.

Property Impairments. Property impairments increased in the year ended December 31, 2007 by $6.1 million to $17.9 million compared to $11.8 million during the year ended December 31, 2006 reflecting higher amortization of lease costs in our existing fields resulting from further defining likely drilling locations and amortization of new fields. Impairment of non-producing properties increased $7.7 million during the year ended December 31, 2007 to $13.1 million compared to $5.4 million for 2006. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

Impairment provisions for developed oil and gas properties were approximately $4.7 million for the year ended December 31, 2007 compared to approximately $6.3 million for the year ended December 31, 2006.

General and Administrative Expense. General and administrative expense increased $1.7 million to $32.8 million during the year ended December 31, 2007 from $31.1 million during the comparable period of 2006. General and administrative expense includes non-cash charges for stock-based compensation of $12.8 million and $10.9 million for the years ended December 31, 2007 and 2006, respectively. The increase was due to new grants under the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) during the year ended December 31, 2007. On a volumetric basis, general and administrative expense was $3.15 per Boe for the year ended December 31, 2007 compared to $3.45 per Boe for the year ended December 31, 2006. We have granted stock options and restricted stock to our employees and directors. While we were a private company, the terms of the grants required us to purchase vested options and restricted stock at each employee s request. The obligation to purchase the options was eliminated when we became a reporting company under Section 12 of the Exchange Act on May 14, 2007.

Gain on Sale of Assets. Gains on miscellaneous asset sales for the year ended December 31, 2007 were approximately $1.0 million compared to $0.3 million for the year ended December 31, 2006.

Interest Expense. Interest expense increased 14%, or $1.6 million for the year ended December 31, 2007 compared to the year ended December 31, 2006, due to a higher average outstanding debt balance on our credit facility. Our average debt balance was $182.2 million for the year ended December 31, 2007 compared to $156.6 million for the year ended December 31, 2006. The weighted average interest rate on our credit facility was slightly higher at 6.47% for the year ended December 31, 2007 compared to 6.36% for the same period in 2006. At December 31, 2007 our outstanding debt balance was $165.0 million.

Income Taxes. Income taxes for the year ended December 31, 2007 were $268.2 million and included $198.4 million recorded to recognize deferred taxes upon the conversion from a subchapter S corporation to a subchapter C corporation on May 14, 2007 for temporary differences that existed at that date primarily as a result of deducting intangible drilling costs for tax purposes. We provide taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences. See Footnote 7 of Notes to Consolidated Financial Statements for more information.

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

Production

The following tables reflect our production by product and region for the periods presented.

	Year ended December 31,				
	2006		2005		Percent
	Volume	Percent	Volume	Percent	Increase
Oil (MBbl)(1)	7,480	83%	5,708	79%	31%
Natural Gas (MMcf)	9,225	17%	9,006	21%	2%
Total (MBoe)	9,018	100%	7,209	100%	25%

	Year ended December 31,				Percent
	2006		2005		increase
	MBoe	Percent	MBoe	Percent	(decrease)
Rocky Mountain	7,159	79%	5,410	75%	32%
Mid-Continent	1,497	17%	1,361	19%	10%
Gulf Coast	362	4%	438	6%	(17)%
Total MBoe	9,018	100%	7,209	100%	25%

(1) Oil sales volumes are 21 MBbls less than oil production volumes for the year ended December 31, 2006.

Oil production volumes increased 31% during the year ended December 31, 2006 in comparison to the year ended December 31, 2005. Production increases in the Bakken field contributed incremental volumes in excess of 2005 levels of 815 MBbls, and the Red River units contributed 865 MBbls of incremental production. Initial production commenced in the Bakken field in August 2003 and has increased thereafter, as we have continued exploration and development activities within the field. Favorable results from the enhanced recovery program and additional field development have been the primary contributors to production growth in the Red River units.

Revenue

Oil and natural gas sales. Oil and natural gas sales for the year ended December 31, 2006 were $468.6 million, a 30% increase over sales of $361.8 million for the comparable period of 2005. Increased sales resulted from additional sales volumes, which increased 25%, and an increase of $1.90 in our realized price per Boe from $50.19 to $52.09. During 2006, we experienced an increase in the differential between NYMEX prices and our realized crude oil prices. The differential per barrel for the twelve months ended December 31, 2006 was $11.04 as compared to $5.24 for the comparable period of 2005. We realized a crude oil differential in December 2006 of $13.32 per Bbl compared to a high of $14.25 per Bbl in March 2006. Among the factors contributing to the higher differentials were higher Canadian oil imports, increases in production in the Rocky Mountain region, refinery downtime in the Rocky Mountain region, downstream transportation capacity constraints, and reduced seasonal demand for gasoline. We are unable to predict when, or if, the differential will revert back to pre-2006 levels.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil, or reclaimed oil. We initiated the sale of high-pressure air from our Red River units to a third party in 2004 and recorded revenues of $3.1 million during 2006 and $3.0 million during 2005. Higher prices for reclaimed oil sold from our central treating unit in 2006 increased oil and natural gas service operations revenues by $0.8 million to $9.4 million at year end 2006. Associated oil and natural gas service operations expenses increased $0.2 million to $8.2 million during the year ended December 31, 2006 from $8.0 million during 2005 due mainly to an increase in the costs of purchasing and treating oil for resale.

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Operating Costs and Expenses

Production Expense and Tax. Production expense increased $10.1 million or 19% during the year ended December 31, 2006 to $62.9 million from $52.8 million during the year ended December 31, 2005. The increase in 2006 was due to increases of $3.8 million in workovers, $1.4 million in energy and chemical costs, $1.5 million in repairs, $1.1 million in overhead, $0.6 million in outside operated well costs, $0.5 million in saltwater disposal expenses, $0.4 million in contract labor costs, and as a result of new wells drilled.

Production taxes increased $6.3 million during the year ended December 31, 2006 to $22.3 million from $16.0 million during 2005. The majority of the production tax increase was $5.9 million in the Rocky Mountain region. Production tax as a percentage of oil and natural gas sales was 4.4% for the year ended December 31, 2005 compared to 4.8% for the year ended December 31, 2006. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, new horizontal wells qualify for a tax incentive and are taxed at 0.76% during the first 18 months of production. After the 18 month incentive period expires, the tax rate increases to 9.26%. During the year ended December 31, 2006, 21 wells reached the end of their exemption period and their tax rate increased from 0.76% to 9.26%. Also in the Rocky Mountain region, 8 wells were added in North Dakota at a rate of 11.5%. As production tax incentives we currently receive for horizontal wells in Montana continue to reach the end of the 18 month incentive period, our overall rate is expected to increase.

On a unit of sales basis, production expense and production taxes were as follows:

	Year ended December 31,		Percent increase
	2006	2005	(decrease)
Production expense ($/Boe)	$ 6.99	$ 7.32	(5)%
Production tax ($/Boe)	2.48	2.22	12%
Production expense and tax ($/Boe)	$ 9.47	$ 9.54	(1)%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $14.5 million in 2006 to $19.7 million due primarily to an increase in dry hole expense of $11.9 million and an increase in seismic expenses of $2.0 million. The Rocky Mountain region contributed 54% of the dry hole costs, 24% was in the Mid-Continent region and the remaining 22% was in the Gulf Coast region. The increase in dry hole expense was due to a higher level of drilling during 2006. Exploration capital expenditures were $68.7 million in 2006 compared to $9.3 million in 2005.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A on oil and gas properties increased $15.3 million in 2006 due to increased production and additional properties being added through our drilling program. The DD&A rate on oil and gas properties for 2005 was $6.50 per Boe compared to $6.91 per Boe for 2006. Accretion expense increased $0.1 million to $1.7 million during 2006 from $1.6 million during 2005.

Property Impairments. Property impairments increased during 2006 by $4.9 million to $11.8 million compared to $6.9 million for 2005. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period. Impairment of non-producing properties increased $1.0 million during 2006 to $5.4 million compared to $4.4 million for 2005.

Impairment provisions for developed oil and gas properties were approximately $2.5 million for the year ended December 31, 2005 and $6.3 million for the year ended December 31, 2006. The increase in 2006 impairment expense resulted primarily from developmental well dry holes and properties where the associated field level reserves were not sufficient to recover capitalized drilling and completion costs.

General and Administrative Expense. General and administrative expense decreased primarily due to a $2.8 million decrease in equity compensation expense net of a charge of $1.5 million associated with our President s non-equity compensation plan as described under Management Summary Compensation Table, associated with restricted stock grants and stock options under our long-term incentive plans. The decrease in equity compensation was attributable to a reduction in the number of equity grants in 2006. On a volumetric basis, general and administrative expense was $3.45 per Boe for 2006 compared to $4.34 per Boe for 2005. We have granted stock options and restricted stock to our employees. The terms of the grants require that, while we are a private company, we are required to purchase vested options and restricted stock at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10. The obligation to purchase the options is eliminated in the event we become a reporting company under Section 12 of the Exchange Act.

Gain on Sale of Assets. During 2005, we realized a gain of $6.1 million on the sale of oil and gas wells and a loss of $3.1 million on the termination of compressor capital leases. Gains in 2006 amounted to approximately $0.3 million on miscellaneous asset sales.

Interest Expense. Interest expense decreased 20% for 2006 due to a lower average outstanding debt balance on our credit facility of $156.6 million compared to $184.0 million for 2005 even though the weighted average interest rate on our credit facility was 6.36% for the year ended December 31, 2006 compared to 5.10% for the year ended December 31, 2005. Additionally, in 2005, we had an outstanding balance due to our principal shareholder for $48.0 million which was paid in full during December 2005. We paid $2.9 million in interest on this note during 2005 at a rate of 6%.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facility and principal shareholder. On May 14, 2007, we completed an initial public offering in which we generated net proceeds of $124.5 million. We believe that funds from operating cash flows and the bank credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months. We intend to fund our longer term cash requirements beyond 12 months through operating cash flows, commercial bank borrowings and access to equity and debt capital markets. Although our longer term needs may be impacted by factors discussed in the section entitled Risk Factors, such as declines in oil and natural gas prices, drilling results, ability to obtain needed capital on satisfactory terms, and other risks which could negatively impact production and our results of operations, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements. On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared. On March 6, 2007, we declared a cash dividend of approximately $33.3 million payable in April 2007 to our shareholders of record as of March 15, 2007, for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of our offering on May 14, 2007, we converted from a subchapter S corporation to a subchapter C corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. At December 31, 2007 and 2006, we had cash and cash equivalents of $8.8 million and $7.0 million, respectively, and available borrowing capacity on our credit facility of $135.0 million and $160.0 million, respectively. At February 29, 2008, we had available borrowing capacity on our credit facility of $178.0 million.

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Cash Flow from Operating Activities

Our net cash provided by operating activities was $390.6 million, $417.0 million and $265.3 million for the years ended December 31, 2007, 2006 and 2005, respectively. The decrease in operating cash flows from $417.0 million in 2006 to $390.6 million in 2007 is the result of increases in oil and gas sales volumes and prices not being fully realized as a result of increases in accounts receivable, inventory, prepaid expenses and accounts payable.

Cash Flow from Investing Activities

During the years ended December 31, 2007, 2006 and 2005 we had cash flows used in investing activities (excluding asset sales) of $486.4 million, $326.6 million and $144.8 million, respectively, in our capital program, inclusive of dry hole and seismic costs. The increases in our capital program in 2007 and 2006 were due to the implementation of enhanced recovery and increased density drilling in our Red River units and additional exploration and development drilling.

Cash Flow from Financing Activities

Net cash provided by (used) in financing activities was $94.6 million for 2007, ($91.5) million for 2006 and ($141.5) million for 2005. In 2005, cash used in financing activities was primarily attributable to the repayment of long-term debt. During 2006, cash used in financing activities was primarily attributable to the payment of cash dividends and during 2007, cash used in financing activities was primarily attributable to financing capital expenditures and the payment of cash dividends. Cash provided by financing activities in 2007 included net of proceeds of $124.5 million from our initial public offering.

Credit Facility

We had $165.0 million and $140.0 million outstanding under our bank credit facility at December 31, 2007 and 2006, respectively. As of February 29, 2008, the amount outstanding under our credit facility has increased by $57.0 million to $222.0 million. The increase was largely due to borrowings to finance the purchase of producing properties from Chesapeake Energy for $55.2 million in January 2008.

The credit facility matures on April 12, 2011, and borrowings under our credit facility bear interest, payable quarterly, at (a) a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months as offered by the lead bank plus an applicable margin ranging from 100 to 175 basis points, depending on the percentage of our borrowing base utilized or (b) the lead bank s reference rate. The credit facility has a note amount of $750.0 million, a borrowing base of $600.0 million, subject to semi-annual redetermination, and a commitment level of $400.0 million. Borrowings under the credit facility are secured by liens on substantially all oil and gas properties and associated assets of the Company. Our next semi-annual redetermination is during April 2008. The terms of the credit facility allow us to determine the commitment level up to the borrowing base.

The credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. The facility also requires us to maintain certain ratios as defined and further described in our credit facility: a Current Ratio of not less than 1.0 to 1.0 (adjusted for available borrowing capacity), a Total Funded Debt to EBITDAX, as defined, of no greater than 3.75 to 1.0. As of December 31, 2007, we were in compliance with all covenants.

Capital Expenditures and Commitments

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas such as the purchase of producing properties in the Williston Basin for $55.2 million in January 2008. Acquisition expenditures are not budgeted.

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We invested approximately $525.7 million (inclusive of non-cash accruals of $36.4 million) for capital and exploration expenditures in 2007 as follows (in millions):

	Amount
Exploration and development drilling	$ 440.7
Purchase of properties	4.2
Dry holes	3.5
Capital facilities, workovers and re-completions	39.1
Land costs	30.8
Seismic	2.9
Vehicles, computers and other equipment	4.5
	$ 525.7

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We have budgeted approximately $616.0 million for capital and exploration expenditures in 2008 as follows (in millions):

	Amount
Exploration and development drilling	$ 490.0
Capital facilities, workovers and re-completions	57.0
Land costs	39.0
Seismic	17.0
Vehicles, computers & other equipment	13.0
	$ 616.0

Our budgeted capital expenditures are expected to increase approximately 17% over the $525.7 million invested during 2007. We plan to invest approximately $272.0 million in development drilling. In the Red River units, we plan to invest approximately $146.0 million to drill infill wells and extend horizontal laterals on existing wells to increase production and sweep efficiency of the enhanced recovery projects. Most of the remaining development drilling budget is expected to be invested in the drilling of development wells in the Montana Bakken field. We have budgeted approximately $218.0 million for exploratory drilling with approximately $65.0 million and $51.0 million allocated to drilling exploratory wells in the North Dakota Bakken field and the Arkoma Woodford project, respectively.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance, cash flows from operations and borrowings available under our credit facility will be sufficient to satisfy our 2008 capital budget. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Shareholder Distribution

On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared, of which $16.9 million was paid to our principal shareholder. On March 6, 2007, we declared a cash dividend of approximately $33.3 million to our shareholders of record and, subject to forfeiture, to holders of unvested restricted stock. On April 12, 2007, we paid $33.1 million of the dividend declared, of which $30.0 million was paid to our principal shareholder. We converted from a subchapter S corporation to a subchapter C corporation on May 14, 2007 when we became a publicly traded company, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

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Obligations and Commitments

We have the following contractual obligations and commitments as of December 31, 2007:

	Payments due by period				
	Total	Less than 1 year	1 - 3 years (in thousands)	3 - 5 years	More than 5 years
Bank credit facility(1)	$ 165,000	$	$	$ 165,000	$
Operating leases	5,956	5,290	644	22	
Asset retirement obligations(2)	42,092	3,939	4,435	758	32,960
Total contractual cash obligations	$ 213,048	$ 9,229	$ 5,079	$ 165,780	$ 32,960

(1) Payments on the bank credit facility listed in the table exclude interest.
(2) Amounts represent expected asset retirements by period.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and notes to our historical consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, derivatives and impairment of assets. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Revenue Recognition

We derive substantially all of our revenues from the sale of oil and natural gas. Oil and gas revenues are recorded in the month the product is delivered to the purchaser and title transfers. We generally receive payment from one to three months after the sale has occurred. Each month we estimate the volumes sold and the price at which they were sold to record revenue. Variances between estimated revenue and actual amounts are recorded in the month payment is received.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized on an individual property, field or unit basis using the unit-of-production method as oil and natural gas is produced. This accounting method may yield significantly different results than the full cost method of accounting.

Depreciation, depletion and amortization, or DD&A, of capitalized drilling and development costs of oil and natural gas properties are generally computed using the unit of production method on an individual property, field or unit basis based on total estimated proved developed oil and natural gas reserves. Amortization of producing leasehold is based on the unit-of-production method using total estimated proved reserves. In arriving

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at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 5 to 40 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value.

Equity Compensation

We account for employee and director stock option grants and restricted stock grants in accordance with SFAS 123(R). The terms of the restricted stock grants and stock option grants stipulated that, until we became a reporting company under Section 12 of the Exchange Act in May 2007, we were required to purchase the vested restricted stock and stock acquired from stock option exercises at each employee s request based upon the purchase price as determined by a formula specified in each award agreement. Additionally, we had the right to purchase vested restricted stock and stock acquired from stock option exercises at the same price upon termination of employment for any reason and for a period of two years subsequent to leaving our employment. Therefore, the awards were accounted for as liability awards in accordance with SFAS 123(R). We measure compensation cost for the awards based upon fair value. Restricted stock and stock option values represent intrinsic value prior to 2006 and fair value after March 7, 2006, the date on which we first filed the registration statement and as a result became a public entity for purposes of SFAS 123(R). Fair value of stock options is determined using the Black-Scholes option valuation model. See *Notes to Consolidated Financial Statements Note 12. Stock Compensation* included elsewhere in this report.

The right to sell and requirement to purchase lapsed when we become a reporting company under Section 12 of the Exchange Act. Therefore, the liability for equity compensation was reclassified to additional paid in capital upon becoming a public reporting company.

The value of granted stock options and restricted stock until March 7, 2006 was based on each grant s intrinsic value. Since March 7, 2006, we have recognized stock-based compensation expense at fair value. We did not prepare or obtain contemporaneous valuations by an unrelated valuation specialist during 2006 because we did not consider it necessary to value our stock options and restricted stock. We utilized the probability-weighted expected return method to estimate the value of our stock option and restricted stock grants. Fair value under this method is estimated based upon an analysis of future values for the grants based upon the probability of various outcomes and the rights of each share class. We considered numerous future outcomes and determined that the outcomes with the highest probability were completion of the initial public offering within one year discounted back to the applicable valuation dates and termination of the initial public offering and continuing as a privately held entity. These alternatives were deemed to be equally likely.

Determining the fair value of our stock based compensation requires making complex and subjective judgments, which are inherently uncertain. The assumptions underlying our estimates are consistent with our understanding and evaluation of different alternatives during 2006 and our discussion of these alternatives with our board of directors, investment bankers and other interested parties. Valuations would have been different had different estimates been utilized.

In calculating the value of stock option grants, we utilized the Black-Scholes option-pricing method. This method requires that we make estimates of the volatility of our equity securities and assess the timing of future events, as previously described. As there was no readily available market for our stock prior to our initial public offering, we based our volatility assumptions on available information on the volatility of the publicly traded stocks of other exploration and production companies considered to be similar in size and operations to us. Had we used different assumptions for volatility, estimated amounts would be different.

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Oil and Natural Gas Reserves and Standardized Measure of Future Cash Flows

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Current accounting guidance allows only proved oil and natural gas reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future DD&A and result in impairment of assets that may be material.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this standard on us relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. SFAS No. 143 requires us to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to the future salvage value of well equipment, future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

Derivatives

The Company accounts for its derivative activities under the guidance provided by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and recognizes all of its derivative instruments as assets or liabilities in the balance sheet at fair value with such amounts classified as current or long-term based on their anticipated settlement. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. In July 2007, the Company entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. The Company has elected not to designate its derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, the Company marks its derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognizes the realized and unrealized change in fair value on derivative instruments in the statements of income. The fair value of derivative liabilities is determined based on the quoted market value of the underlying NYMEX commodity contracts. See *Notes to Consolidated Financial Statement Note 5. Derivative Contracts* for more information. The Company had no open hedges at December 31, 2006 or 2005.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions to oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Recent Accounting Pronouncements

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 did not have a material impact on the Company s consolidated financial position or results of operations. The Company s policy is to recognize penalties and interest, if any, in income tax expense.

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* which will become effective in 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. In February 2008, the FASB granted a one-year deferral of the effective date of this statement as it applies to nonfinancial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and goodwill impairment). The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in our Consolidated Financial Statements beginning in the first quarter of 2008. The impact from adoption relating to financial assets and liabilities is not expected to be significant; however the impact, if any, from the adoption relating to non-financial assets and liabilities will depend on the Company s assets and liabilities at the time they are required to be measured at fair value.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115.* This Statement provides entities with an option to choose to measure eligible items at fair value at specified election dates. If elected, an entity must report unrealized gains and losses on the item in earnings at each subsequent reporting date. The fair value option: may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; is irrevocable (unless a new election date occurs); and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Management does not believe that the implementation of SFAS No. 159 will have a material impact on our consolidated financial position or results of operation.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (SFAS 160). SFAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for both public and private companies for fiscal years beginning on or after December 15, 2008 (fiscal 2009 for the Company). SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. Early adoption is prohibited for both standards. The adoption of SFAS 141(R) and SFAS 160 is not expected to have a material impact on our consolidated financial position or results of operation.

Inflation

Historically, general inflationary trends have not had a material effect on our operating results. However, we have experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increase in drilling activity and competitive pressures resulting from higher oil and natural gas prices in recent years.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which may include the use of derivative instruments.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates. See *Notes to Consolidated Financial Statements. Note 1. Organization and Summary of Significant Accounting Policies.* We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. Although we have not generally required our counterparties to provide collateral to support trade receivables owed to us, we routinely require prepayment of working interest holders proportionate share of drilling costs. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk.

Commodity Price Risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past, through the utilization of derivatives, including zero-cost collars and fixed price contracts. We had no hedging contracts in place during 2006 or through June 30, 2007. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we will receive a fixed-price of $72.90 per barrel and will pay to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we mark our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognize the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of income. As of December 31, 2007 we recorded a liability for unrealized losses on derivatives of $26.7 million. During the year ended December 31, 2007, we had realized losses on derivatives of $18.2 million. As of December 31, 2007, a one dollar increase or decrease in the NYMEX crude futures price would result in approximately $1.2 million loss or gain over the remaining life of our derivatives. At February 29, 2008 the fair market value of unrealized derivatives losses was $17.3 million. In addition, we had realized losses on derivatives for January and February 2008 of $12.7 million.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility. We had total indebtedness of $222.0 million outstanding under our credit facility at February 29, 2008. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $2.2 million and a $1.4 million decrease in net income. Our weighted average interest rate at December 31, 2007 was 6.26%. Since year end we have experienced a reduction in interest rates as our credit facility tranches mature and are renewed. Our weighted average interest rate at February 29, 2008 was 5.62%. The fair value of long-term debt is estimated based on quoted market prices and management s estimate of current rates available for similar issues. The following table itemizes our long-term debt maturities and the weighted-average interest rates by maturity date:

	2008	2009	2010	2011	2012	Total
				(in thousands)		
Variable rate debt:						
Credit facility:						
Principal amount	$	$	$	$ 165.0	$	$ 165.0
Weighted-average interest rate				6.26%		6.26%

Item 8. Financial Statements and Supplemental Data
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Report of Independent Registered Public Accounting Firm

Board of Directors

Continental Resources, Inc.

We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. and Subsidiary as of December 31, 2007 and 2006, and the related consolidated statements of income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2007. 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 standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Continental Resources, Inc. and Subsidiary as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 13, 2008

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Continental Resources, Inc. and Subsidiary

Consolidated Balance Sheets

	December 31, 2007	December 31, 2006
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 8,761	$ 7,018
Receivables:		
Oil and natural gas sales	95,165	55,037
Affiliated parties	17,146	7,698
Joint interest and other, net	50,779	26,351
Inventories	19,119	7,831
Deferred and prepaid taxes	12,159	
Prepaid expenses and other	2,435	1,046
Total current assets	205,564	104,981
Net property and equipment, based on successful efforts method of accounting	1,157,926	751,747
Debt issuance costs, net	1,683	2,201
Total assets	$ 1,365,173	$ 858,929
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 127,730	$ 100,414
Accounts payable trade to affiliated parties	15,090	13,727
Accrued liabilities and other	25,295	43,230
Revenues and royalties payable	67,349	28,738
Unrealized derivative losses	26,703	
Current portion of asset retirement obligation	3,939	2,528
Total current liabilities	266,106	188,637
Long-term debt	165,000	140,000
Other noncurrent liabilities:		
Deferred tax liability	271,424	
Asset retirement obligation, net of current portion	38,153	38,745
Other noncurrent liabilities	1,358	1,086
Total other noncurrent liabilities	310,935	39,831
Commitments and contingencies (Notes 8 and 9)		
Shareholders equity:		
Preferred stock, $0.01 par value: 25,000,000 shares authorized; no shares issued and outstanding		
Common stock, $.01 par value; 500,000,000 shares authorized; 168,864,015 shares issued and outstanding at December 31, 2007; 159,106,244 shares issued and outstanding at December 31, 2006	1,689	144
Additional paid-in-capital	415,435	27,087
Retained earnings	206,008	463,255
Accumulated other comprehensive loss, net of tax		(25)
Total shareholders equity	623,132	490,461

Total liabilities and shareholders equity	$ 1,365,173	$ 858,929

The accompanying notes are an integral part of these consolidated financial statements.

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Income

	Year ended December 31, 2007	2006	2005
	(In thousands, except share data)		
Revenues:			
Oil and natural gas sales	$ 572,610	$ 374,304	$ 252,947
Oil and natural gas sales to affiliates	33,904	94,298	108,886
Loss on mark-to-market derivative instruments	(44,869)		
Oil and natural gas service operations	20,570	15,050	13,931
Total revenues	582,215	483,652	375,764
Operating costs and expenses:			
Production expense	57,562	45,694	39,709
Production expense to affiliates	18,927	17,171	13,045
Production tax	32,562	22,331	16,031
Exploration expense	9,163	19,738	5,231
Oil and natural gas service operations	12,709	8,231	7,977
Depreciation, depletion, amortization and accretion	93,632	65,428	49,802
Property impairments	17,879	11,751	6,930
General and administrative	32,802	31,074	31,266
Gain on sale of assets	(988)	(290)	(3,026)
Total operating costs and expenses	274,248	221,128	166,965
Income from operations	307,967	262,524	208,799
Other income (expense):			
Interest expense	(12,939)	(11,310)	(11,326)
Interest expense to affiliates			(2,894)
Other	1,749	1,742	867
	(11,190)	(9,568)	(13,353)
Income before income taxes	296,777	252,956	195,446
Provision (benefit) for income taxes	268,197	(132)	1,139
Net income	$ 28,580	$ 253,088	$ 194,307
Basic net income per share	$ 0.17	$ 1.60	$ 1.23
Diluted net income per share	0.17	1.59	1.22
Dividends per share	0.33	0.55	0.01
Pro forma (unaudited):			
Income before income taxes	$ 296,777	$ 252,956	$ 195,446
Provision for income taxes	112,775	96,123	74,269
Net income	$ 184,002	$ 156,833	$ 121,177
Basic net income per share	$ 1.12	$ 0.97	$ 0.77
Diluted net income per share	1.11	0.96	0.76

See Note 1 relating to pro forma information.

The accompanying notes are an integral part of these consolidated financial statements.

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Shareholders Equity

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income (loss)	Total shareholders equity
			(In thousands, except share data)			
Balance, January 1, 2005	158,058,109	$ 144	$ 25,087	$ 105,154	$	$ 130,385
Comprehensive income:						
Net income				194,307		194,307
Other comprehensive income					38	38
Total comprehensive income						194,345
Issuance of restricted stock	990,517					
Capital contribution			2,000			2,000
Dividends				(2,000)		(2,000)
Balance, December 31, 2005	159,048,626	144	27,087	297,461	38	324,730
Comprehensive income:						
Net income				253,088		253,088
Other comprehensive loss					(63)	(63)
Total comprehensive income						253,025
Stock options exercised	22,660					
Restricted stock:						
Issuance	200,772					
Repurchased and cancelled	(23,309)					
Stock withheld for taxes	(37,356)					
Forfeited	(105,149)					
Dividends				(87,294)		(87,294)
Balance, December 31, 2006	159,106,244	$ 144	$ 27,087	$ 463,255	$ (25)	$ 490,461
Comprehensive income:						
Net income				28,580		28,580
Other comprehensive income, net of tax					25	25
Total comprehensive income						28,605
Public offering of common stock	8,850,000	89	124,406			124,495
Reclass for stock split		1,447	(1,447)			
Adjust for undistributed earnings from conversion to subchapter C corporation			234,099	(234,099)		
Reclass stock compensation liability to equity			29,828			29,828
Stock-based compensation			3,874			3,874
Tax benefit on share-based compensation plan			1,630			1,630
Stock options:						
Exercised	689,476	7	619			626
Repurchased and canceled	(292,313)	(3)	(3,079)			(3,082)
Restricted stock:						
Issued	629,684	6				6
Repurchased and canceled	(77,441)	(1)	(1,476)			(1,477)
Forfeited	(41,635)		(106)			(106)
Dividends				(51,728)		(51,728)

Balance, December 31, 2007	168,864,015	$ 1,689	$ 415,435	$ 206,008	$	$ 623,132

The accompanying notes are an integral part of these consolidated financial statements.

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Continental Resources, Inc. and Subsidiary

Consolidated Statements of Cash Flows

	Year ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 28,580	$ 253,088	$ 194,307
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	95,604	65,540	49,802
Property impairments	17,879	11,751	6,930
Change in derivative fair value	26,703		
Amortization of debt issuance costs and other	657	900	1,662
Gain on sale of assets	(988)	(290)	(3,026)
Dry hole costs	3,549	13,344	1,432
Equity compensation	12,791	10,932	13,715
Tax benefit of excess nonqualified stock option deduction	(1,630)		
Provision for deferred income taxes	262,412		
Changes in assets and liabilities:			
Accounts receivable	(74,004)	(11,739)	(39,194)
Inventories	(11,288)	(3,005)	766
Prepaid expenses and other	(2,837)	(386)	371
Accounts payable	(7,760)	77,422	12,205
Revenues and royalties payable	38,611	(2,917)	19,033
Accrued liabilities and other	2,009	2,297	6,456
Other noncurrent liabilities	360	104	806
Net cash provided by operating activities	390,648	417,041	265,265
Cash flows from investing activities:			
Exploration and development	(477,663)	(313,071)	(140,591)
Purchase of other property and equipment	(4,610)	(6,944)	(1,942)
Purchase of oil and gas properties	(4,166)	(6,564)	(2,267)
Proceeds from sale of assets	2,941	2,056	11,084
Net cash used in investing activities	(483,498)	(324,523)	(133,716)
Cash flows from financing activities:			
Line of credit	288,500	286,000	25,000
Repayment of shareholder note			(48,000)
Repayment of line of credit and other borrowings	(263,500)	(289,000)	(112,464)
Proceeds from initial public offering, net	124,495		
Payment of stock-based compensation	(5,075)		(3,915)
Dividends to shareholders	(52,036)	(87,373)	(2,000)
Debt issuance costs	(90)	(1,107)	(88)
Exercise of options	644	29	
Tax benefit of excess non qualified stock option deduction	1,630		
Net cash provided by (used in) financing activities	94,568	(91,451)	(141,467)
Effect of exchange rate changes on cash and cash equivalents	25	(63)	38
Net change in cash and cash equivalents	1,743	1,004	(9,880)
Cash and cash equivalents at beginning of period	7,018	6,014	15,894
Cash and cash equivalents at end of period	$ 8,761	$ 7,018	$ 6,014

The accompanying notes are an integral part of these consolidated financial statements.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

Description of Company

Continental Resources, Inc. is incorporated under the laws of the State of Oklahoma. It was originally formed in 1967 to explore, develop and produce oil and natural gas properties in Oklahoma. Through 1993, its activities and growth remained focused primarily in Oklahoma. In 1993, the Company expanded its activity into the Rocky Mountain and Gulf Coast regions. Through drilling success and strategic acquisitions, approximately 82% of its estimated proved reserves as of December 31, 2007 are located in the Rocky Mountain region. As of December 31, 2007, the Company had interests in 1,822 wells and serves as the operator of 1,306 of these wells.

On May 14, 2007, the Company completed its initial public offering. In conjunction therewith, the Company affected an 11 for 1 stock split by means of a stock dividend. All prior period share and per share information contained in this report has been retroactively restated to give effect to the stock split. On May 14, 2007, the Company amended its certificate of incorporation to, among other things, increase the number of authorized preferred shares to 25 million and common shares to 500 million. Prior to completion of the public offering, the Company was a subchapter S corporation and income taxes were payable by its shareholders. In connection with the public offering, the Company converted to a subchapter C corporation.

Basis of presentation

Continental had one wholly owned subsidiary, Continental Resources of Illinois, Inc. (CRII) at December 31, 2005. CRII was incorporated in June 2001 for the purpose of acquiring the assets of Farrar Oil Company and Har-Ken Oil Company. Continental acquired Banner Pipeline Company, L.L.C. (Banner) on March 30, 2006 for approximately $8.8 million, which represented the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable. CRII was merged into Continental on October 12, 2006. Banner was Continental s only subsidiary at December 31, 2007 and 2006.

All significant inter-company accounts and transactions have been eliminated in the consolidated financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Of the estimates and assumptions that affect reported results, the estimate of the Company s oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing oil and gas properties, is the most significant.

Pro forma information (unaudited)

Pro forma adjustments are reflected on the consolidated statements of income to provide for income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109 Accounting for Income Taxes as if the Company had been a subchapter C corporation for all periods presented. For unaudited pro forma income tax calculations, deferred tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities were measured using enacted tax rates expected to apply to taxable income in the years in which the Company expects to recover or settle those temporary differences. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for all periods. The pro forma tax effects are based upon

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

currently available information. Management believes that these assumptions provide a reasonable basis for representing the pro forma tax effects.

The pro forma information should be read in conjunction with the related historical information and is not necessarily indicative of the results that would have been attained had the transactions actually taken place.

Revenue recognition

Oil and natural gas sales result from interests owned by the Company in oil and natural gas properties. Sales of oil and natural gas produced from oil and natural gas operations are recognized when the product is delivered to the purchaser and title transfers to the purchaser. The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has under-produced or over-produced its ownership percentage in a property. Under this method, a receivable or liability is recognized only to the extent that an imbalance can not be recouped from the reserves in the underlying properties. The Company s aggregate imbalance positions at December 31, 2007 and 2006 were not material. Charges for gathering and transportation are included in production expenses.

Cash and cash equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The Company maintains its cash and cash equivalents in accounts that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to significant credit risk.

Accounts receivable

The Company operates exclusively in oil and natural gas exploration and production related activities. Oil and natural gas sales and joint interest receivables are generally unsecured. Accounts receivable are due within 30 days and considered delinquent after 60 days. The Company determines its allowance for doubtful accounts by considering a number of factors, including the length of time accounts are past due, the Company s loss history, and the customer or working interest owner s ability to pay. The Company writes off specific accounts when they become uncollectible and any payments subsequently received on these receivables are credited to the allowance for doubtful accounts. The following table presents the allowance for doubtful accounts at December 31, 2005, 2006 and 2007 and changes in the allowance for these years:

	Balance at beginning of period	Additions charged to costs and expenses	Deductions	Balance at end of period
Year ended December 31, 2005	$ 252,972	$ 59,378	$ (140,899)	$ 171,451
Year ended December 31, 2006	171,451	68,178	(46,303)	193,326
Year ended December 31, 2007	193,326			193,326

Concentration of credit risk

The Company is subject to credit risk resulting from the concentration of its crude oil and natural gas receivables with several significant customers. The largest purchasers of the Company s oil and gas production accounted for 44% (three purchasers), 33% (two purchasers) and 60% (three purchasers) of total oil and natural gas sales revenues for 2007, 2006 and 2005, respectively. These purchasers constituted all purchasers with oil

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

and natural gas sales in excess of 10% of total oil and natural gas sales. The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as oil and natural gas are fungible products with well-established markets and numerous purchasers.

Inventories

Inventories are stated at the lower of cost or market. Inventory consists primarily of tubular goods and production equipment, which totaled approximately $4.7 million and $4.2 million at December 31, 2007 and 2006, respectively, and crude oil line fill and temporary storage of approximately $14.4 million, representing 384,000 barrels of crude oil, and $3.6 million, representing 95,000 barrels of crude oil, at December 31, 2007 and 2006, respectively.

Property and equipment

Property and equipment are capitalized and stated at cost, while maintenance and repairs are expensed as incurred.

Depreciation and amortization are provided in amounts sufficient to expense the cost of depreciable assets to operations over their estimated useful lives using the straight-line method. Estimated useful lives are as follows:

Property and Equipment	**Useful Lives in Years**
Furniture and fixtures	10
Automobiles	5
Machinery and equipment	10-20
Office and computer equipment	5
Building and improvements	10-40

Oil and gas properties

The Company uses the successful efforts method of accounting for oil and gas properties whereby costs to acquire mineral interests in oil and gas properties, drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Geological and geophysical costs, seismic costs, lease rentals and costs associated with unsuccessful exploratory wells are expensed as incurred. Maintenance and repairs are expensed as incurred, except that the cost of replacements or renewals that expand capacity or improve production are capitalized.

The Company reports capitalized exploratory drilling costs on the balance sheet according to SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies . On a monthly basis, the Company capitalizes the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. The Company capitalizes costs associated with the acquisition or construction of support equipment and facilities with the drilling and development costs to which they relate. If proved reserves are found by an exploratory well, associated capitalized costs become part of well equipment and facilities; however, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value. Total capitalized exploratory drilling costs, as of December 31, 2007 and 2006, pending the determination of proved reserves were $32.9 million and $10.0 million, respectively. As of December 31, 2007, exploratory drilling costs of $3.1 million representing five wells were suspended beyond one year and are expected to be fully evaluated in 2008. Of the suspended costs, $2.9 million was incurred in 2006 and the balance in 2007. All five projects were drilled in 2006.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Production expenses are those costs incurred by the Company to operate and maintain its oil and natural gas properties and associated equipment and facilities. Production expenses include labor costs to operate the Company s properties, repairs and maintenance, and materials and supplies utilized in the Company s operations.

The Company accounts for its asset retirement obligations pursuant to SFAS No. 143, Accounting for Asset Retirement Obligations which requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs are charged to expense through the depreciation, depletion and amortization of oil and gas properties and the liability is accreted to the expected abandonment amount over the asset s life.

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on its oil and natural gas properties and related facilities disposal. The following table summarizes the changes in the Company s future abandonment liability from January 1, 2005 through December 31, 2007 (in thousands):

	2007	2006	2005
Asset retirement obligation liability at January 1,	$ 41,273	$ 34,353	$ 34,192
Asset retirement obligation accretion expense	1,962	1,680	1,596
Plus: Revisions	(1,817)	4,391	
Additions for new assets	2,453	2,480	1,031
Less: Plugging costs and sold assets	(1,779)	(1,631)	(2,466)
Asset retirement obligation liability at December 31,	$ 42,092	$ 41,273	$ 34,353

As of December 31, 2007 and 2006, property and equipment included $27.5 million, $27.7 million, respectively, of net asset retirement costs.

Depreciation, depletion, amortization, accretion and impairment

Depreciation, depletion, and amortization (DD&A) of capitalized drilling and development costs, including related support equipment and facilities, of producing oil and gas properties are computed using the units of production method on an individual property, field or unit basis based on total estimated proved developed oil and gas reserves. Amortization of producing leasehold is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by the Company s geologists, engineers and independent reserve engineers. Upon sale or retirement of properties, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least in conjunction with its semi-annual reserve reports. Revisions are accounted for prospectively as changes in accounting estimates.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on the Company s estimated experience of successful drilling and the average holding period. Impairment of non-producing properties was $13.2 million, $5.4 million and $4.4 million for 2007, 2006, and 2005 respectively.

In accordance with the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , the Company recognizes impairment expenses for developed oil and gas properties and other long-lived assets when indicators of impairment are present and the undiscounted cash flows from proved and

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

risk-adjusted probable reserves are not sufficient to recover the assets carrying amount. The impairment loss is measured by comparing the fair value of the asset to its carrying amount. Fair values are based on discounted future cash flows. The Company s oil and gas properties are reviewed for indicators of impairment on a field-by-field basis, resulting in the recognition of impairment provisions of $4.7 million, $6.3 million and $2.5 million, respectively, for 2007, 2006 and 2005. The majority of the impairment recognized in these years relates to fields comprised of a small number of properties or single wells on which the Company does not expect sufficient future net cash flows to recover its carrying cost.

Debt issuance costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized over the term of the related debt. The Company had capitalized costs of $1.7 million and $2.2 million (net of accumulated amortization of $5.0 million and $4.5 million) relating to the issuance of its long-term debt at December 31, 2007 and 2006, respectively. During the years ended December 31, 2007, 2006 and 2005, the Company recognized associated amortization expense of $0.6 million, $0.9 million and $1.7 million, respectively. Debt issuance costs are capitalized and amortized on a straight-line basis, the use of which approximates the effective interest method, over the life of the credit facility.

Derivatives

The Company accounts for its derivative activities under the guidance provided by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended, and recognizes all of its derivative instruments as assets or liabilities in the balance sheet at fair value with such amounts classified as current or long-term based on their anticipated settlement. The fair value of unrealized derivative losses at December 31, 2007 was $26.7 million. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation.

Fair value of financial instruments

The Company s financial instruments consist primarily of cash, trade receivables, trade payables and long-term debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short maturity of these instruments.

The fair value of long-term debt approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The estimated fair value of long-term debt is $165.0 million and $140.0 million at December 31, 2007 and 2006, respectively.

Income taxes

On May 14, 2007, the Company completed its initial public offering. Prior to completion of the public offering, the Company was a subchapter S corporation and income taxes were payable by its shareholders. In connection with the public offering, the Company converted to a subchapter C corporation and recorded a charge to income in the second quarter of $198.4 million to initially recognize deferred taxes at May 14, 2007. Thereafter, the Company has provided for income taxes on income. In 2005, the Company recorded federal income tax expense of $1.1 million attributable to gains on sales of properties where the fair market value at the date of conversion into a subchapter S corporation exceeded their tax basis and the properties were sold within 10 years of the conversion in accordance with section 1374 of the Internal Revenue Code. The benefit recorded during 2006 reflects a change in estimate of the original provision recorded.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Equity compensation

The Company accounts for employee stock option grants and restricted stock grants in accordance with SFAS 123(R). The terms of the restricted stock and stock option grants stipulate that, prior to its initial public offering, the Company was required to purchase vested restricted stock and stock acquired from stock option exercises at each employee s request based upon the purchase price as determined by a formula specified in each award agreement. Additionally, the Company had the right to purchase vested restricted stock and stock acquired from stock option exercises at the same price upon termination of employment for any reason and for a period of two years subsequent to leaving the employment of the Company. Therefore, the awards were accounted for as liability awards in accordance with SFAS 123(R). The Company measures compensation cost for the awards based upon fair value. Restricted stock and stock option values represent intrinsic value prior to 2006 and fair value after March 6, 2006, when the Company became a public entity under SFAS 123(R). Fair value of stock options is determined using the Black-Scholes option valuation model.

The right to sell and requirement to purchase lapsed when the Company became a reporting company under Section 12 of the Exchange Act. Therefore, the liability for equity compensation was reclassified to additional paid in capital in May 2007.

Earnings per common share

Basic earnings per common share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution of non-vested restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if these options were exercised. The following is the calculation of basic and diluted weighted average shares outstanding and earning per share computations for the years ended December 31, 2007, 2006 and 2005:

	2007	2006	2005
	(in thousands, except per share data)		
Income (numerator):			
Net income basic and diluted	$ 28,580	$ 253,088	$ 194,307
Weighted average shares (denominator):			
Weighted average shares basic	164,059	158,114	158,059
Restricted stock	211	300	160
Employee stock options	1,152	1,251	1,088
Weighted average shares diluted	165,422	159,665	159,307
Earnings per share:			
Basic	$ 0.17	$ 1.60	$ 1.23
Diluted	$ 0.17	$ 1.59	$ 1.22

Comprehensive income

The Company classifies other comprehensive income (loss) items by their nature in the consolidated financial statements and displays the accumulated balance of other comprehensive income (loss) separately in the

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

shareholders equity section of the balance sheet. Accumulated other comprehensive income (loss) at December 31, 2006 consisted of foreign currency translation related to its Canadian assets and operations. In 2007, the Company sold its Canadian properties.

Recent accounting pronouncements

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes.* The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 did not have a material impact on the Company s consolidated financial position or results of operations. The Company s policy is to recognize penalties and interest, if any, in income tax expense.

In September 2006, the FASB finalized SFAS No. 157, Fair Value Measurements , which is effective for the Company January 1, 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. In February 2008, the FASB granted a one-year deferral of the effective date of this statement as it applies to nonfinancial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and goodwill impairment). The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in the Company s Consolidated Financial Statements beginning in the first quarter of 2008. The impact from adoption relating to financial assets and liabilities is not expected to be significant; however the impact, if any, from the adoption relating to non-financial assets and liabilities will depend on the Company s assets and liabilities at the time they are required to be measured at fair value.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 . This Statement provides entities with an option to choose to measure eligible items at fair value at specified election dates. If elected, an entity must report unrealized gains and losses on the item in earnings at each subsequent reporting date. The fair value option may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; is irrevocable (unless a new election date occurs); and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Management does not believe that the implementation of SFAS No. 159 will have a material impact on the Company s consolidated financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS 141(R)) and SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (SFAS 160). SFAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for the Company for fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. Early adoption is prohibited for both standards. The adoption of SFAS 141(R) and SFAS 160 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

2. Cash Flow Information

Net cash provided by operating activities reflects cash payments as follows (in thousands):

		December 31,	
	2007	2006	2005
Interest paid	$ 11,499	$ 10,875	$ 14,598
Income taxes paid	6,988	1,007	

Noncash investing and financing activities are as follows (in thousands):

		December 31,	
	2007	2006	2005
Capital contribution note payable forgiven by shareholder	$	$	$ 2,000
Cancellation of capital leases			10,058
Asset retirement obligations	636	6,871	1,031

3. Property, Plant, and Equipment

Property, plant and equipment includes the following at December 31, 2007 and 2006 (in thousands):

	2007	2006
Proved oil and natural gas properties	$ 1,518,981	$ 1,032,108
Unproved oil and natural gas properties	65,830	57,309
Service properties, equipment and other	29,000	25,668
Total property and equipment	1,613,811	1,115,085
Accumulated depreciation, depletion and amortization	(455,885)	(363,338)
Net property and equipment	$ 1,157,926	$ 751,747

4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2007 and 2006 (in thousands):

	2007	2006
Equity compensation	$ 850	$ 22,502
Prepaid drilling costs	4,002	7,235
Accrued salaries	5,604	4,180
Production taxes payable	10,805	6,632
Other	4,034	2,681
Total accrued liabilities and other	$ 25,295	$ 43,230

5. Derivative Contracts

In July 2007, the Company entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008 to partially reduce price risk. During each month of the contract, the Company will receive a fixed-price of $72.90 per barrel and will pay to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities requires recognition of all derivative

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has elected not to designate its derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, the Company marks its derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognizes the realized and unrealized change in fair value on derivative instruments in the statements of income. As of December 31, 2007 the Company had recorded a liability for unrealized losses on derivatives of $26.7 million. For the year ended December 31, 2007, the statement of income contains realized losses of $18.2 million and unrealized losses of $26.7 million on derivatives. The Company did not have any derivative contracts in 2006 or 2005.

6. Long-term Debt

The Company had $165.0 million and $140.0 million in long-term debt outstanding at December 31, 2007 and 2006, respectively, on its credit facility due April 11, 2011. At the Company s election, the maturity date can be extended for up to two one-year periods. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months, as elected by the Company, plus a margin ranging from 100 to 175 basis points, depending on the percentage of its borrowing base utilized, or the lead banks reference rate. The credit facility has a maximum facility amount of $750.0 million, a borrowing base of $600.0 million (effective November 28, 2007), subject to semi-annual re-determination, and a commitment level of $300.0 million at December 31, 2007. Under the terms of the credit facility, the Company is allowed to set the commitment level up to the borrowing base. During January 2008, the Company increased the commitment level to $400.0 million. Borrowings under the credit facility are secured by liens on substantially all oil and gas properties and associated assets of the Company.

The Company had $135.0 million of unused commitments under the Credit Agreement at December 31, 2007 and incurs commitment fees of 0.2% of the daily average excess of the commitment amount over the outstanding credit balance. The credit facility contains certain covenants including that the Company maintain a current ratio of not less than 1.0 to 1.0 (inclusive of availability under the Credit Agreement) and a Total Funded Debt to EBITDAX, as defined, of no greater than 3.75 to 1.0. The Company was in compliance with these covenants at December 31, 2007.

The Company s weighted average interest rate was 6.26% at December 31, 2007. At December 31, 2007, the Company had $2.2 million of outstanding letters of credit that expire during 2008.

7. Income Taxes

The following is an analysis of the Company s income tax provision in conjunction with and subsequent to the conversion to a subchapter C corporation on May 14, 2007. Prior to this date, the Company was a subchapter S corporation and income taxes were payable by its shareholders.

	Year ended December 31, 2007 (in thousands)
Current:	
Federal	$ 5,785
State	
Total current provision	5,785
Deferred:	
Federal	233,801
State	28,611

Total deferred provision		262,412
Income tax provision	$	268,197

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

The following table reconciles the income tax provision with income tax at the Federal statutory rate for the year ended December 31, 2007.

	Year ended December 31, 2007 (in thousands)
Federal tax at statutory rate	$ 103,872
State income taxes, net of federal benefit	7,716
Eliminate taxes on earnings prior to subchapter C corporation conversion(1)	(32,380)
Non-deductible stock-based compensation	1,090
Other, net	1,770
Earnings transferred to subchapter S corporation through election of pro-rata allocation method(2)	(12,275)
Deferred taxes recorded upon conversion to a subchapter C corporation	198,404
Income tax provision	$ 268,197

(1) Federal tax at the statutory rate and state income taxes have been calculated based upon the net income before tax for the year. However, the Company converted from a subchapter S corporation to a subchapter C corporation on May 14, 2007 and deferred taxes were provided for temporary differences that existed on that date. This adjustment eliminates the taxes related to the net income before tax from the beginning of the year presented through May 14, 2007, which tax effects are already included in deferred taxes recorded upon conversion to a subchapter C corporation.

(2) The Company calculated its estimate of income allocation to the subchapter S corporation period assuming the use of the pro-rata income allocation method for tax purposes instead of the specific identification method used for financial reporting purposes. Using the pro-rata income allocation method, the Company s income for the year is allocated to the subchapter S corporation and the subchapter C corporation based on number of days without regard to when the income was actually earned.

Significant components of the Company s deferred tax assets and liabilities as of December 31, 2007 are as follows:

	December 31, 2007 (in thousands)
Current:	
Deferred tax assets	
Unrealized losses on derivatives(1)	$ 10,040
Other expenses	602
Total current deferred tax assets	10,642
Noncurrent:	
Deferred tax assets	
Net operating loss carryforward	4,553
Alternative minimum tax carryforward	6,537
Deferred compensation	1,952
Other	438
Total noncurrent deferred tax assets	13,480
Deferred tax liabilities	
Property and equipment	284,904

Net noncurrent deferred tax liabilities		271,424
Net deferred tax liabilities	$	260,782

(1) Deferred and prepaid taxes on the consolidated Balance Sheet contains prepaid taxes of $1.2 million.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

As of December 31, 2007, the Company had a net operating loss carryforward of $12.1 million which will expire beginning in 2027. In addition, the Company has an alternative minimum tax credit carryforward of $6.5 million and a statutory depletion carryforward, which will be recognized when realized, of $1.5 million, neither of which expire.

8. Lease Commitments

The Company leases office space under operating leases from the principal shareholder (See Note 10).

The Company had a capital lease arrangement to lease compressors from a related party. In 2005, the capital lease contract was cancelled and the Company executed an operating lease effective January 28, 2005. The Company recorded a loss of $3.1 million on the termination of the capital lease. The Company pays approximately $400,000 per month under the operating lease. The term of the operating lease is through January 28, 2009.

Lease expense associated with the Company s operating leases for the years ended December 31, 2007, 2006 and 2005, was $6.0 million, $5.9 million and $5.3 million, respectively. At December 31, 2007, including leases renewed and entered into subsequent to December 31, 2007, the minimum future rental commitments under operating leases having noncancelable lease terms in excess of one year, including leases from related parties, are as follows (in thousands):

Year	Leases with related parties	Leases with unrelated parties	Total amount
2008	$ 4,943	$ 347	$ 5,290
2009	402	162	564
2010		80	80
2011		21	21
2012		1	1
Total obligations	$ 5,345	$ 611	$ 5,956

9. Commitments and Contingencies

During the three years ended December 31, 2007, the Company maintains a defined contribution retirement plan for its employees and makes discretionary contributions to the plan based on a percentage of each eligible employees compensation. During 2007, 2006 and 2005, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Expense for the years ended December 31, 2007, 2006 and 2005, was $881,000, $790,000 and $663,000, respectively.

Health and workers compensation claims made by employees up to the first $125,000 and $250,000, respectively, per claim are self-insured by the Company. Any amounts paid above these are reinsured through third-party providers. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. At December 31, 2007 and 2006, the accrued liability for health claims was $636,000 and $629,000, respectively.

The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will have a material adverse effect on the financial position or results of operations of the Company. As of December 31, 2007 and 2006, the Company has provided a reserve of $1.0 million and $0.7 million, respectively, for various matters none of which are believed to be individually significant.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Due to the nature of the oil and gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

10. Related Party Transactions

The Company currently markets a portion of its natural gas sales to an affiliate. Prior to February 2006, the Company marketed a portion of its oil sales to an affiliate. During the years ended December 31, 2007, 2006, and 2005, these sales were approximately $33.9 million, $94.3 million, and $108.9 million. The Company also contracts for field services such as compression and drilling rig services and purchases residue fuel gas and reclaimed oil from certain affiliates. Production expense attributable to these affiliates was $18.9 million, $17.2 million and $13.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. The total amount paid to these companies, a portion of which was billed to other interest owners, was approximately $76.3 million, $52.9 million and $38.6 million during the years ended December 31, 2007, 2006 and 2005, respectively. The Company operated crude oil gathering lines in North Dakota and Wyoming on behalf of an affiliated company for which they paid the Company approximately $346,000 during 2007. At December 31, 2007 and 2006, approximately $17.1 million and $7.7 million was due from affiliates and approximately $15.1 million and $13.7 million was due to affiliates, respectively.

Certain officers of the Company own or control entities that own working and royalty interest in wells operated by the Company. The Company paid revenues, including royalties, of approximately $10.4 million, $7.9 million, and $5.6 million and billed expenses of $9.1 million, $5.2 million, and $4.2 million during the years ended December 31, 2007, 2006, and 2005, respectively, to these affiliates. The Company also paid them $199,000 in 2007 for their share of undeveloped leasehold sales.

The Company leases office space under an operating lease from a company owned by the Company s principal shareholder. Rents paid associated with this lease totaled approximately $707,000, $638,000 and $556,000 for the years ended December 31, 2007, 2006 and 2005, respectively. The term of the lease is through February 2009 at an annual rate of approximately $740,000.

On November 22, 2004, the Company entered into a subordinated note with the principal shareholder, which required the Company to make quarterly interest payments beginning December 31, 2004. Interest paid during 2005 was $2.9 million. During 2005, the principal shareholder forgave $2.0 million of this note and a contribution to paid-in capital was recorded. The outstanding balance of $48.0 million was paid on December 27, 2005.

Under a contract for gas sales to an affiliate the Company pays $0.60 per Mcf for gathering and treating fees which amounted to $1.1 million in 2007.

11. Shareholders Equity

On May 14, 2007, the Company completed its initial public offering of 29,500,000 shares of its common stock at $15.00 per share. The shares are listed on the New York Stock Exchange under the symbol CLR. The Company sold 8,850,000 shares of common stock in the offering and Harold G. Hamm, the Chairman and Chief Executive Officer and principal shareholder of the Company, sold 20,650,000 shares of common stock in the offering. The offering generated gross proceeds of $132.8 million to the Company. The Company incurred underwriters discounts of approximately $8.0 million and other expenses of approximately $2.3 million. The Company netted $290,000, representing 30% of the costs incurred after the Company decided to participate in the offering, against the proceeds of the offering. The balance of the offering costs were expensed as incurred. After the payment of offering expenses, the net proceeds were used to repay a portion of the outstanding indebtedness under the credit facility.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

On May 14, 2007, the Company affected an 11 for 1 stock split by means of a stock dividend. All prior period share and per share information contained in these consolidated financial statements has been retroactively restated to give effect to the stock split. On May 14, 2007, the Company amended its certificate of incorporation to, among other things, increase the number of authorized preferred shares to 25 million and common shares to 500 million.

On May 14, 2007 the Company converted from a subchapter S corporation to a subchapter C corporation. As a result, the Company recorded an adjustment in the amount of $234.1 million to reduce retained earnings to $65.1 million as of the conversion date, which represents the retained earnings balance of the Company when it originally converted from a subchapter C corporation to a subchapter S corporation in May 1997. The amount of the adjustment represents undistributed earnings of $432.5 million, net of the related provision for deferred income taxes of $198.4 million (which was included in the determination of net income for the year ended December 31, 2007).

The Company accounts for stock option grants and restricted stock grants in accordance with SFAS 123(R). The terms of the restricted stock grants and stock option grants stipulate that prior to the Company s initial public offering, it was required to purchase the vested restricted stock and stock acquired from stock option exercises at each employee s request. Therefore, the awards were accounted for as liability awards in accordance with SFAS 123(R). The right to sell and requirement to purchase lapsed when the Company completed its initial public offering. Therefore, the liability for equity compensation of approximately $29.8 million was reclassified to additional paid-in capital on May 14, 2007.

On January 10, 2007 and March 6, 2007, the Company declared cash dividends of approximately $18.8 million and $33.3 million to its shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. During 2007, the Company paid cash dividends of $52.0 million.

During 2006, the Company declared cash dividends totaling $87.6 million to existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. During 2006, the Company paid cash dividends of $87.4 million.

12. Stock Compensation

Stock Options

Effective October 1, 2000, the Company adopted the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and granted options to eligible employees. These options were either incentive stock options, nonqualified stock options or a combination of both. The granted stock options vest ratably over either a three or five-year period commencing on the first anniversary of the grant date and expire ten years from date of grant. On November 10, 2005, the 2000 Plan was terminated. As of December 31, 2007, options covering 1,427,136 shares had been exercised and 365,650 had been cancelled.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

The Company s stock option activity under the 2000 plan from December 31, 2004 to December 31, 2007 was as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding December 31, 2004	1,837,000	$ 1.31	1,307,526	$ 0.94
Granted	275,000	5.71		
Exercised	(440,000)	0.95		
Outstanding December 31, 2005	1,672,000	2.13	1,206,337	1.14
Exercised	(22,660)	1.26		
Canceled	(73,337)	3.97		
Outstanding December 31, 2006	1,576,003	2.06	1,370,666	1.59
Exercised	(689,476)	1.66		
Outstanding December 31, 2007	886,527	2.28	794,853	1.88

The total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005 was $11.1 million, $0.1 million and $3.2 million, respectively. The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option at its exercise date. At December 31, 2007, the outstanding options had a weighted average life of 4.26 years and an aggregate intrinsic value of $21.1 million. At December 31, 2007, the exercisable options had a weighted average life of 3.91 years and an aggregate intrinsic value of $19.3 million. As of December 31, 2007, there was $103,000 of unrecognized compensation expense related to non-vested stock options. The expense is expected to be recognized over a weighted average period of 0.3 years.

Effective January 1, 2006, the Company adopted SFAS 123(R), using the modified-prospective transition method. The adoption did not have a material effect on the Company s consolidated financial position or results of operations. In connection with the filing of a registration statement with the Securities and Exchange Commission on March 7, 2006, for the public offering of common stock, the Company became a public entity for purposes of SFAS 123(R). For public entities, stock option liability awards are required to be valued using the Black-Scholes or similar option valuation model. In connection therewith, the Company changed from the intrinsic value method to the fair value method of accounting for its stock options and restricted stock. In determining the fair value of the vested stock options and compensation expense as of and for the years ended December 31, 2007 and 2006, the Company utilized the Black-Sholes option pricing value model based on a fair value for stock option grants of $11.96 per share, weighted average expected life of 2.38 years, expected volatility of 38%, weighted average risk-free interest rate of 4.75% and a dividend yield of zero. The expected life is based on management s expectations of option exercises. The volatility is based on the average volatility of our peer group for a period approximating the expected life of the options. The risk-free interest rate is based on treasury rates in effect at December 31, 2006 commensurate with the expected life of the stock options.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

The following table summarizes information about stock options outstanding at December 31, 2007:

Options Outstanding				Options Exercisable	
Exercise Prices	Number outstanding	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable	Weighted average exercise price
$0.71	195,840	4.31 years	$ 0.71	195,840	$ 0.71
$1.27	465,000	2.75 years	1.27	465,000	1.27
$5.71	225,687	7.33 years	5.71	134,013	5.71
	886,527		$ 2.28	794,853	$ 1.88

Restricted Stock

On October 3, 2005, the Company adopted the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of December 31, 2007, the Company had 3,934,151 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. All grants were made on or after October 3, 2005. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants vest over periods ranging from one to three years.

Pursuant to the award agreements, the Company had the right to purchase vested restricted shares and shares acquired by option exercise at all times the employee remained in the employment of the Company and for a period of two years subsequent to leaving the employment of the Company and grantees had the right to require the Company to purchase vested restricted shares and shares acquired by option exercise, each at a purchase price as determined by a formula specified in each award agreement, prior to completion of its initial public offering in May 2007. All grants of stock options were issued with an exercise price equal to the then estimated fair value of the Company s stock determined according to the plans. Before becoming a public reporting entity, the awards were accounted for as liability awards. The amount reflected on the accompanying consolidated balance sheet as liabilities as of December 31, 2006 was $22.5 million. The associated liability was transferred to additional paid in capital in May 2007 when the purchase rights lapsed. The Company s associated compensation expense, included in general and administrative expense, was $12.8 million, $10.9 million and $13.7 million during 2007, 2006 and 2005, respectively.

The Company issued 990,517 shares of restricted stock during 2005. A summary of changes in the non-vested restricted shares for the period of December 31, 2005 to December 31, 2007, is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares as of December 31, 2005	990,517	$ 13.40
Granted	200,772	13.27
Vested	(304,733)	13.40
Forfeited	(105,149)	13.45
Non-vested restricted shares as of December 31, 2006	781,407	13.36
Granted	629,684	22.12

Vested	(321,750)	13.27
Forfeited	(41,635)	14.15
Non-vested restricted shares as of December 31, 2007	1,047,706	18.36

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

The fair value of the restricted shares that vested during 2007 at their vesting date was $4.3 million. As of December 31, 2007, there was $14.6 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.8 years.

13. Oil and Gas Property Information

The following table sets forth the Company s results of operations from oil and natural gas producing activities for the years ended December 31, 2007, 2006 and 2005 (in thousands):

Prior to the completion of the Company s initial public offering, the Company was a subchapter S corporation and its taxes were payable by its shareholders. The table below shows taxes from May 14, 2007 to the end of the year at statutory rates and pro forma for the remaining periods.

		December 31,	
	2007	2006	2005
Oil and natural gas sales	$ 606,514	$ 468,602	$ 361,833
Production expense and tax	(109,051)	(85,196)	(68,785)
Exploration expense	(9,163)	(19,738)	(5,231)
Depreciation, depletion, amortization and accretion	(91,678)	(63,810)	(48,425)
Property impairments	(17,879)	(11,751)	(6,930)
Income taxes	(102,676)		
Results from oil and natural gas producing activities	$ 276,067	$ 288,107	$ 232,462

		December 31,	
(Unaudited)	2007	2006	2005
Pro forma presentation for income tax:			
Results from oil and natural gas producing activities before pro forma income tax	$ 378,743	$ 288,107	$ 232,462
Pro forma income tax	(143,922)	(109,481)	(88,336)
Pro forma oil and natural gas producing activities	$ 234,821	$ 178,626	$ 144,126

Costs incurred in oil and gas activities

Costs incurred, both capitalized and expensed, in connection with the Company s oil and gas acquisition, exploration and development activities for the three years ended December 31, 2007, 2006 and 2005 are shown below (in thousands).

	2007	2006	2005
Property acquisition costs:			
Proved	$ 4,166	$ 6,564	$ 2,267
Unproved	21,729	29,970	14,496
Total property acquisition costs	25,895	36,534	16,763
Exploration costs	181,883	68,686	9,289
Development costs	316,741	221,286	117,837
Total	$ 524,519	$ 326,506	$ 143,889

Exploration costs above include asset retirement costs of $236,000, $214,000 and $305,000 and development costs above include asset retirement costs of $401,000, $6,658,000 and $726,000 for the years 2007, 2006 and 2005, respectively.

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Aggregate capitalized costs

Aggregate capitalized costs relating to the Company s oil and gas producing activities, and related accumulated depreciation, depletion and amortization as of December 31, 2007 and 2006 are as follows (in thousands):

	2007	2006
Proved oil and natural gas properties	$ 1,518,981	$ 1,032,108
Unproved oil and natural gas properties	65,830	57,309
Total	1,584,811	1,089,417
Less-accumulated depreciation, depletion and amortization	(440,700)	(349,192)
Net capitalized costs	$ 1,144,111	$ 740,225

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. When initial drilling operations are complete, management determines whether the well has discovered oil and gas reserves and, if so, whether those reserves can be classified as proved. Often, the determination of whether proved reserves can be recorded under Securities and Exchange Commission (SEC) guidelines can not be made when drilling is completed. In those situations where management believes that commercial hydrocarbons have not been discovered, the exploratory drilling costs are reflected in the Consolidated Statement of Income as dry hole costs (a component of exploration expense). Where sufficient hydrocarbons have been discovered to justify further exploration or appraisal activities, exploratory drilling costs are deferred on the Consolidated Balance Sheet pending the outcome of those activities.

At the end of each quarter, operating and financial management review the status of all deferred exploratory drilling costs in light of ongoing exploration activities in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts. If management determines that future appraisal drilling or development activities are not likely to occur, any associated exploratory well costs are expensed in that period.

The following table presents the amount of capitalized exploratory drilling costs pending evaluation at December 31 for each of the last three years and changes in those amounts during the years then ended (in thousands):

	2007	2006	2005
Balance, January 1	$ 10,049	$ 1,874	$ 3,237
Additions to capitalized exploratory well costs pending determination of proved reserves	139,765	65,721	8,984
Reclassification to proved oil and natural gas properties based on the determination of proved reserves	(113,329)	(44,203)	(8,915)
Capitalized exploratory well costs charged to expense	(3,549)	(13,343)	(1,432)
Balance, December 31	$ 32,936	$ 10,049	$ 1,874
Number of projects	45	26	13

14. Supplemental Oil and Gas Information (Unaudited)

The following table shows estimates of proved reserves prepared by the Company s technical staff and independent external reserve engineers in accordance with SEC definitions. Ryder Scott Company prepared

Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

reserve estimates for properties comprising 85% of the Company s standardized measure of discounted future net cash flows as of December 31, 2007 and 83% of the Company s standardized measure of discounted future net cash flows as of December 31, 2006 and 2005. Remaining reserve estimates were prepared by the Company s technical staff. Substantially all reserves stated here are located in the United States of America.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that can not be precisely measured, and estimates of engineers other than the Company s might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered.

Gas imbalance receivables and liabilities for each of the three years ended December 31, 2007, 2006 and 2005, were not material and have not been included in the reserve estimates.

Proved oil and gas reserves

	Natural Gas (MMcf)	**Crude Oil (MBbls)**
Proved reserves as of December 31, 2004	60,620	80,602
Revisions of previous estimates	1,431	1,653
Extensions, discoveries and other additions	54,823	23,290
Production	(9,006)	(5,708)
Sale of minerals in place		(1,292)
Purchase of minerals in place	250	100
Proved reserves as of December 31, 2005	108,118	98,645
Revisions of previous estimates	(307)	416
Extensions, discoveries and other additions	23,235	6,111
Production	(9,225)	(7,480)
Purchase of minerals in place	44	346
Proved reserves as of December 31, 2006	121,865	98,038
Revisions of previous estimates	7,434	2,134
Extensions, discoveries and other additions	64,988	12,845
Production	(11,534)	(8,699)
Sale of minerals in place		(228)
Purchase of minerals in place	66	55
Proved reserves as of December 31, 2007	182,819	104,145

The increases in oil and natural gas reserve volumes attributable to extensions, discoveries and other additions are a result of the Company s exploration and development activity.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped oil and natural gas reserves of the Company as of December 31, 2005, 2006 and 2007:

Proved Developed Reserves	Natural Gas (MMcf)	Crude Oil (MBbls)	Oil Equivalent (MBoe)
December 31, 2005	54,257	71,259	80,302
December 31, 2006	70,420	75,336	87,073
December 31, 2007	128,831	79,756	101,228

Proved Undeveloped Reserves	Natural Gas (MMcf)	Crude Oil (MBbls)	Oil Equivalent (MBoe)
December 31, 2005	53,861	27,386	36,363
December 31, 2006	51,445	22,702	31,276
December 31, 2007	53,988	24,389	33,387

Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that require incremental capital expenditures to recover. Natural gas is converted to barrels of oil equivalent using a conversion factor of six thousand cubic feet per barrel.

Standardized measure of discounted future net cash flows relating to proved oil and gas reserves

The standardized measure of discounted future net cash flows presented in the following table was computed using year-end prices and costs and a 10% discount factor. However, the Company cautions that actual future net cash flows may vary considerably from these estimates. Although the Company s estimates of total proved reserves, development costs and production rates were based on the best available information, the development and production of the oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flows computations should not be considered to represent the Company s estimate of the expected revenues or the current value of existing proved reserves.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

Prior to the completion of the Company s initial public offering on May 14, 2007, the Company was a subchapter S corporation where taxes were paid by its shareholders. In connection with the completion of its initial public offering, the Company converted to a subchapter C corporation, a taxable entity. As such we are showing taxes in our standardized measure as of December 31, 2007, but not for prior years. Taxes as of the end of prior years are shown in the pro forma presentation.

	December 31,		
	2007	2006	2005
		(in thousands)	
Historical			
Future cash inflows	$ 9,754,787	$ 5,244,078	$ 6,332,258
Future production costs	(2,427,862)	(1,763,573)	(1,808,654)
Future development and abandonment costs	(461,811)	(466,057)	(434,249)
Future income taxes	(2,008,293)		
Future net cash flows	4,856,821	3,014,448	4,089,355
10% annual discount for estimated timing of cash flows	(2,274,482)	(1,429,976)	(1,884,980)
Standardized measure of discounted future net cash flows	$ 2,582,339	$ 1,584,472	$ 2,204,375
Pro forma for income tax			
Future cash inflows		$ 5,244,078	$ 6,332,258
Future production costs		(1,763,573)	(1,808,654)
Future development and abandonment costs		(466,057)	(434,249)
Future income taxes		(1,061,163)	(1,497,230)
Future net cash flows pro forma for income taxes		1,953,285	2,592,125
10% annual discount for estimated timing of cash flows		(926,588)	(1,194,834)
Standardized measure of discounted future net cash flows		$ 1,026,697	$ 1,397,291

The year-end weighted average oil price utilized in the computation of future cash inflows was $82.86, $47.85, and $55.87 per barrel at December 31, 2007, 2006 and 2005, respectively. The year-end weighted average natural gas price utilized in the computation of future cash inflows was $6.16, $4.54, and $7.60 per Mcf at December 31, 2007, 2006 and 2005, respectively. Future cash flows are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs, based on year-end cost estimates assuming continuation of existing economic conditions.

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Continental Resources, Inc. and Subsidiary

Notes to Consolidated Financial Statements (continued)

The changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company s proved oil and gas reserves are presented below for each of the past three years (in thousands):

	2007	2006	2005
Standardized measure of discounted future net cash flows at the beginning of the year	$ 1,584,472	$ 2,204,375	$ 1,114,320
Extensions, discoveries and improved recovery, less related costs	643,016	138,119	566,858
Revisions of previous quantity estimates	90,188	5,455	43,338
Change in estimated future development and abandonment costs	(14,597)	(139,623)	(317,286)
Purchase (sales) of minerals in place	2,050	5,953	(8,714)
Net change in prices and production costs	1,313,657	(520,756)	870,255
Accretion of discount	158,447	220,438	111,432
Sales of oil and natural gas produced, net of production costs	(497,463)	(383,405)	(287,817)
Development costs incurred during the period	232,356	123,971	48,894
Change in timing of estimated future production and other	15,677	(70,055)	63,095
Change in income taxes	(945,464)		
Net Change	997,867	(619,903)	1,090,055
Standardized measure of discounted future net cash flows at the end of the year	$ 2,582,339	$ 1,584,472	$ 2,204,375

15. Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2007 and 2006 is summarized below.

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
2007				
Revenues	$ 121,123	$ 145,326	$ 156,772	$ 158,994
Operating income	$ 57,162	$ 74,134	$ 88,368	$ 88,303
Net income (loss)	$ 53,814	$ (142,498)	$ 56,372	$ 60,892
Net income (loss) per share:				
Basic	$ 0.34	$ (0.87)	$ 0.34	$ 0.36
Diluted	$ 0.34	$ (0.87)	$ 0.33	$ 0.36
2006				
Revenues	$ 103,765	$ 125,101	$ 140,873	$ 113,913
Operating income	$ 52,458	$ 68,604	$ 90,443	$ 51,019
Net income	$ 50,293	$ 66,061	$ 87,991	$ 48,743
Net income per share:				
Basic	$ 0.32	$ 0.42	$ 0.56	$ 0.31
Diluted	$ 0.32	$ 0.41	$ 0.55	$ 0.31

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

There have been no changes in accountants or any disagreements with accountants.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rule 240.13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in reports that it files or submits with this report accumulated and communicated to the issuer s management, including its Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, as appropriate to make timely decisions regarding required disclosures. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer have concluded that our current disclosure controls and procedures are effective to ensure that information required to be disclosed by us in this report are recorded, processed, summarized and reported, within the time periods specified.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Management s Report on Internal Control Over Financial Reporting

This annual report does not include a report of management s assessment regarding internal control over financial reporting or a report of our independent registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held May 27, 2008, (Annual Meeting) and is incorporated herein by reference.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

The information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed as Exhibit 3.1 to the Company s Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
3.2	Second Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company s Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
4.1	Registration Rights Agreement filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
4.2	Specimen Common Stock Certificate filed as Exhibit 4.1 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.1	Sixth Amended and Restated Credit Agreement among Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., The Royal Bank of Scotland plc, other financial institutions and banks and Continental Resources, Inc. dated April 12, 2006 filed as Exhibit 10.1 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.2	Omnibus Agreement among Continental Resources, Inc., Hiland Partners, LLC, Harold Hamm, Hiland Partners GP, LLC, Continental Gas Holdings, Inc. and Hiland Partners, LP effective as of the closing of Hiland Partners, LP s initial public offering of common units (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.3	Compression Services Agreement among Hiland Partners, LP and Continental Resources, Inc. effective as of January 28, 2005 (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
10.4	Gas Purchase Contract between Continental Resources, Inc. and Hiland Partners, LP dated November 8, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Hiland Partners, LP filed on November 10, 2005, Commission File No. 000-51120).
10.5	Strategic Customer Relationship Agreement among Complete Energy Services, Inc., CES Mid-Continent Hamm, Inc. and Continental Resources, Inc. dated October 14, 2004 (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-1 of Complete Production Services, Inc. filed on November 15, 2005, Commission File No. 333-128750).
10.6	Continental Resources, Inc. 2000 Stock Option Plan filed as Exhibit 10.6 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.7	First Amendment to Continental Resources, Inc. 2000 Stock Option Plan filed as Exhibit 10.7 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.8	Form of Incentive Stock Option Agreement filed as Exhibit 10.8 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.9	Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006 filed as Exhibit 10.9 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.

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10.10	Form of Restricted Stock Award Agreement filed as Exhibit 10.10 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.11	Amended and Restated Employment Agreement between Continental Resources, Inc. and Mark E. Monroe dated April 3, 2006 filed as Exhibit 10.11 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.12	Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof filed as Exhibit 10.12 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.13	Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006 filed as Exhibit 10.13 to the Company s registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.14	Crude oil gathering agreement between Banner Pipeline Company, LLC, a wholly owned subsidiary of Continental Resources, Inc. and Banner Transportation Company dated July 11, 2007 filed as Exhibit 99.1 to the Company s Current Report on Form 8-K filed July 11, 2007 and incorporated herein by reference.
21.1*	Subsidiaries of Continental Resources, Inc.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of the Company s Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)
31.2*	Certification of the Company s Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241)
32*	Certification of the Company s Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

* Filed herewith

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Signatures

Pursuant to the requirements Section 13 on 15 (d) of the Securities Exchange Act of 1934, Continental Resources, Inc. has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in Enid, Oklahoma, on this 13th day of March, 2008.

CONTINENTAL RESOURCES, INC.

By:	/s/ Mark E. Monroe
Name:	**Mark E. Monroe**
Title:	**President and Chief Operating Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report Statement on Form S-1 has been signed by the following persons on behalf of Continental Resources, Inc. in the capacities and on the dates indicated.

Signature	**Title**	**Date**
* **Harold G. Hamm**	Chairman, Chief Executive Officer and Director (principal executive officer)	March 13, 2008
/s/ Mark E. Monroe **Mark E. Monroe**	President, Chief Operating Officer and Director	March 13, 2008
* **John D. Hart**	Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	March 13, 2008
* **Jack H. Stark**	Senior Vice President Exploration and Director	March 13, 2008
* **Robert J. Grant**	Director	March 13, 2008
* **George S. Littell**	Director	March 13, 2008
* **Lon McCain**	Director	March 13, 2008
* **H. R. Sanders, Jr.**	Director	March 13, 2008

*By: /s/ Mark E. Monroe
Mark E. Monroe

Attorney-in-Fact