CONTINENTAL RESOURCES, INC
Form 10-K
February 28, 2013
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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, 2012

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.)**
20 N. Broadway, Oklahoma City, Oklahoma	**73102**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (405) 234-9000

Securities registered pursuant to Section 12(b) of the Act:

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

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

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

Indicate by check mark if the 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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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 the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2012 was approximately $3.8 billion, based upon the closing price of $66.62 per share as reported by the New York Stock Exchange on such date.

185,602,632 shares of our $0.01 par value common stock were outstanding on February 15, 2013.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Continental Resources, Inc. for the Annual Meeting of Shareholders to be held in May 2013, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Form 10-K.

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When we refer to us, we, our, Company, or Continental we are describing Continental Resources, Inc. and our subsidiaries.

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Glossary of Crude Oil and Natural Gas Terms

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

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

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 crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.

Btu British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

completion The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.

conventional play An area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

DD&A Depreciation, depletion, amortization and accretion.

de-risked Refers to acreage and locations in which the Company believes the geological risks and uncertainties related to recovery of crude oil and natural gas have been reduced as a result of drilling operations to date. However, only a portion of such acreage and locations have been assigned proved undeveloped reserves and ultimate recovery of hydrocarbons from such acreage and locations remains subject to all risks of recovery applicable to other acreage.

developed acreage The number of acres allocated or assignable to productive wells or wells capable of production.

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

dry gas Refers to natural gas that remains in a gaseous state in the reservoir and does not produce large quantities of liquid hydrocarbons when brought to the surface. Also may refer to gas that has been processed or treated to remove all natural gas liquids.

dry hole Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.

ECO-Pad™ A Continental Resources, Inc. trademark which describes a well site layout which allows for drilling multiple wells from a single pad resulting in less environmental impact and lower drilling and completion costs.

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

exploratory well A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir.

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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 differs from nearby rock.

held by production or *HBP* Refers to an oil and gas lease continued into effect into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

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.

HPAI High pressure air injection.

hydraulic fracturing A process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production.

in-field well A well drilled between producing wells in a field to provide more efficient recovery of crude oil or natural gas from the reservoir.

injection well A well into which liquids or gases are injected in order to push additional crude oil or natural gas out of underground reservoirs and into the wellbores of producing wells. Typically considered an enhanced recovery process.

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

MBoe One thousand Boe.

Mcf One thousand cubic feet of natural gas.

Mcfe One thousand cubic feet of natural gas equivalent, with one barrel of crude oil being equivalent to six Mcf of natural gas based on the average equivalent energy content of the two commodities.

MMBo One million barrels of crude oil.

MMBoe One million Boe.

MMBtu One million British thermal units.

MMcf One million cubic feet of natural gas.

MMcfe One million cubic feet of natural gas equivalent, with one barrel of crude oil being equivalent to six Mcf of natural gas based on the average equivalent energy content of the two commodities.

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 a 50% interest in 100 acres owns 50 net acres.

play A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.

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

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prospect A potential geological feature or formation which geologists and geophysicists believe may contain hydrocarbons. A prospect can be in various stages of evaluation, ranging from a prospect that has been fully evaluated and is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

proved reserves The quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain.

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

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

PV-10 When used with respect to crude oil and natural gas reserves, PV-10 represents 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 Securities and Exchange Commission (SEC). PV-10 is not a financial measure calculated in accordance with generally accepted accounting principles (GAAP) 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. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Company s crude oil and natural gas properties. The Company 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.

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

resource play Refers to an expansive contiguous geographical area with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and multi-stage fracturing technologies.

royalty interest Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

SCOOP Refers to the South Central Oklahoma Oil Province, a term we use to describe an emerging area of crude oil and liquids-rich properties located in the Anadarko basin of the Oklahoma Woodford formation.

spacing The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-acre spacing) and is often established by regulatory agencies.

standardized measure Discounted future net cash flows estimated by applying the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January to December 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 the tax basis in the crude oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

step-out well or *step outs* A well drilled beyond the proved boundaries of a field to investigate a possible extension of the field.

3D (three dimensional seismic) defined locations Locations that have been subjected to 3D seismic testing. We typically use 3D seismic testing to evaluate reservoir presence and/or continuity. We do not typically evaluate reservoir productivity using 3D seismic technology.

3D seismic Seismic surveys using an instrument to send sound waves into the earth and collect data to help geophysicists define the underground configurations. 3D seismic provides three-dimensional pictures.

unconventional play An area believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as is the case with oil and gas shale, tight oil and gas sands and coalbed methane.

undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

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 a crude oil reservoir to push additional crude oil out of the reservoir rock and into the wellbores of producing wells. Typically an enhanced recovery process.

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

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

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Cautionary Statement for the Purpose of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact, including, but not limited to, statements or information concerning the Company s future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, returns, budgets, costs, business strategy, objectives, and cash flow, included in this report are forward-looking statements. When used in this report, the words could, may, believe, anticipate, intend, estimate, expect, project, budget, plan, continue, potential, gu similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements are based on the Company s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes the expectations reflected in the forward-looking statements are reasonable and based on reasonable assumptions, no assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under *Part I, Item 1A. Risk Factors* included in this report, quarterly reports, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

Without limiting the generality of the foregoing, certain statements incorporated by reference, if any, or included in this report constitute forward-looking statements.

Forward-looking statements may include statements about:

- our business strategy;
- our future operations;
- our reserves;
- our technology;
- our financial strategy;
- crude oil, natural gas liquids, and natural gas prices and differentials;
- the timing and amount of future production of crude oil and natural gas and flaring activities;
- the amount, nature and timing of capital expenditures;
- estimated revenues, expenses and results of operations;
- drilling and completing wells;

competition;

marketing of crude oil and natural gas;

transportation of crude oil, natural gas liquids, and natural gas to markets;

exploitation or property acquisitions and dispositions;

costs of exploiting and developing our properties and conducting other operations;

our financial position;

general economic conditions;

credit markets;

our liquidity and access to capital;

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- the impact of governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us and of scheduled or potential regulatory or legal changes;

- our future operating results;

- plans, objectives, expectations and intentions contained in this report that are not historical, including, without limitation, statements regarding our future growth plans;

- our commodity hedging arrangements; and

- the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us.

We caution you these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for, and development, production, and sale of, crude oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling, completion and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, and the other risks described under *Part I, Item 1A. Risk Factors* in this report, quarterly reports, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements to reflect events or circumstances after the date of this report.

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Part I

You should read this entire report carefully, including the risks described under Part I, Item 1A. Risk Factors and our consolidated financial statements and the notes to those 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 the Company refer to Continental Resources, Inc. and its subsidiaries.

Item 1. Business

General

We are an independent crude oil and natural gas exploration and production company with properties in the North, South and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, and the Red River units. The South region includes Kansas and all properties south of Kansas and west of the Mississippi River including the South Central Oklahoma Oil Province (SCOOP), Northwest Cana and Arkoma Woodford plays in Oklahoma. The SCOOP and Northwest Cana plays were previously combined by the Company and referred to as the Anadarko Woodford play. In December 2012, we sold the producing crude oil and natural gas properties in our East region. Our remaining East region properties are comprised of undeveloped leasehold acreage east of the Mississippi River that will be managed as part of our exploration program.

We were originally formed in 1967 to explore for, develop and produce crude oil and natural gas properties. Through 1989, our activities and growth remained focused primarily in Oklahoma. In 1989, we expanded our activity into the North region. Approximately 82% of our estimated proved reserves as of December 31, 2012 are located in the North region. We completed an initial public offering of our common stock in 2007, and our common stock trades on the New York Stock Exchange 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 allow us to economically develop and produce crude oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drill bit, adding 649.0 MMBoe of proved crude oil and natural gas reserves through extensions and discoveries from January 1, 2008 through December 31, 2012 compared to 86.7 MMBoe added through proved reserve acquisitions during that same period. In October 2012, we announced a new five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017.

As of December 31, 2012, our estimated proved reserves were 784.7 MMBoe, with estimated proved developed reserves of 317.8 MMBoe, or 40% of our total estimated proved reserves. Crude oil comprised 72% of our total estimated proved reserves as of December 31, 2012. For the year ended December 31, 2012, we generated crude oil and natural gas revenues of $2.4 billion and operating cash flows of $1.6 billion. For the year ended December 31, 2012, daily production averaged 97,583 Boe per day, a 58% increase over average production of 61,865 Boe per day for the year ended December 31, 2011. Average daily production for the quarter ended December 31, 2012 increased 42% to 106,831 Boe per day from 75,219 Boe per day for the quarter ended December 31, 2011.

The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2012, average daily production for the quarter ended December 31, 2012 and the reserve-to-production index in our principal regions. Our reserve estimates as of December 31, 2012 are based primarily on a reserve report prepared by our independent reserve engineers, Ryder Scott Company, L.P (Ryder Scott). In preparing its report, Ryder Scott evaluated properties representing approximately 99% of our PV-10, 99% of our proved crude oil reserves, and 96% of our proved natural gas reserves as of December 31, 2012. Our internal technical staff evaluated the remaining properties. Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure at December 31, 2012 were determined using the 12-month unweighted

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arithmetic average of the first-day-of-the-month commodity prices for the period of January 2012 through December 2012, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $94.71 per Bbl for crude oil and $2.76 per MMBtu for natural gas ($86.56 per Bbl for crude oil and $4.31 per Mcf for natural gas adjusted for location and quality differentials).

	At December 31, 2012				Average daily production for fourth quarter 2012 (Boe per day)		
	Proved reserves (MBoe)	Percent of total	PV-10 (1) (In millions)	Net producing wells		Percent of total	Annualized reserve/production index (2)
North Region:							
Bakken field							
North Dakota Bakken	517,686	66.0%	$ 8,891	494	59,019	55.2%	24.0
Montana Bakken	45,883	5.8%	995	176	8,503	8.0%	14.8
Red River units							
Cedar Hills	55,808	7.1%	1,573	139	11,058	10.4%	13.8
Other Red River units	22,445	2.9%	430	121	3,658	3.4%	16.8
Other	3,147	0.4%	48	11	967	0.9%	8.9
South Region:							
Oklahoma Woodford							
SCOOP (3)	62,893	8.0%	955	34	7,123	6.7%	24.2
Northwest Cana (3)	44,888	5.7%	211	73	9,716	9.1%	12.7
Arkoma Woodford	22,042	2.8%	61	60	3,225	3.0%	18.7
Other	9,885	1.3%	145	286	2,556	2.4%	10.6
East Region (4)					1,006	0.9%	
Total	784,677	100.0%	$ 13,309	1,394	106,831	100.0%	20.1

(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. Standardized Measure at December 31, 2012 is $11.2 billion, a $2.1 billion difference from PV-10 because of the income tax effect. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the crude oil and natural gas 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 income tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years that estimated proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2012 production into estimated proved reserve volumes at December 31, 2012.

(3) The SCOOP and Northwest Cana plays were previously combined by the Company and referred to as the Anadarko Woodford play.

(4) In December 2012, we sold the producing crude oil and natural gas properties in our East region. No proved reserves have been recorded for the East region as of December 31, 2012. See *Part II, Item 8. Notes to Consolidated Financial Statements Note 13. Property Acquisitions and Dispositions* for further discussion of the transaction.

The following table provides additional information regarding our key development areas as of December 31, 2012 and the budgeted amounts we plan to spend on exploratory and development drilling, capital workovers, and facilities in 2013.

	Developed acres		Undeveloped acres		2013 Plan	
					Gross wells planned for drilling	Capital expenditures (1) (in millions)
	Gross	Net	Gross	Net		
North Region:						

Bakken field							
North Dakota Bakken	758,998	473,068	619,786	393,899	507	$	2,132
Montana Bakken	127,276	107,053	219,029	165,783	51		427
Red River units	150,450	135,483			10		63
Niobrara - Colorado/Wyoming	11,271	7,726	183,985	103,585	13		32
Other	22,427	8,491	191,916	104,741	35		102
South Region:							
Oklahoma Woodford							
SCOOP	33,023	21,995	379,793	196,172	90		466
Northwest Cana	115,742	71,539	156,001	106,893	2		5
Arkoma Woodford	107,402	26,291	12,064	5,302			1
Other	96,803	45,896	115,169	80,197	16		102
East Region			210,742	190,474			
Total	1,423,392	897,542	2,088,485	1,347,046	724	$	3,330

(1) The capital expenditures budgeted for 2013 as reflected above include amounts for drilling, capital workovers and facilities and exclude budgeted amounts for land of $220 million, seismic of $20 million, and $30 million for vehicles, computers and other equipment. Potential acquisition expenditures are not budgeted. We expect our cash flows from operations, our remaining cash balance, and our revolving credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to satisfy our 2013 capital budget. We may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, available cash flows, unbudgeted acquisitions, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of transportation capacity, and regulatory, technological and competitive developments. Further, a decline in crude oil and natural gas prices could cause us to curtail our actual capital expenditures. Conversely, an increase in commodity prices could result in increased capital expenditures.

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 crude oil. During the late 1980s we began to believe the valuation potential for crude oil exceeded that of natural gas. Accordingly, we began to shift our reserve and production profiles toward crude oil. As of December 31, 2012, crude oil comprised 72% of our total proved reserves and 70% of our 2012 annual production. Although we do pursue liquids-rich natural gas opportunities, such as those found in the SCOOP, we continue to believe crude oil valuations will be superior to natural gas valuations on a relative Btu basis for the foreseeable future.

Growth Through Drilling. A substantial portion of our annual capital expenditures are invested in drilling projects and acreage acquisitions. From January 1, 2008 through December 31, 2012, proved crude oil and natural gas reserve additions through extensions and discoveries were 649.0 MMBoe compared to 86.7 MMBoe of proved reserve acquisitions.

Internally Generated Prospects. Although we periodically evaluate and complete strategic acquisitions, our technical staff has internally generated a substantial portion 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 later entrants into a developing play.

Focus on Unconventional Crude Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional crude oil and natural gas resource reservoirs, such as the Red River B Dolomite, Bakken, and Oklahoma Woodford formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technologies including water and high pressure air injection. Our production from the Red River units, the Bakken field, and the Oklahoma Woodford play comprised approximately 33,831 MBoe, or 95%, of our total crude oil and natural gas production for the year ended December 31, 2012.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 971,634 net undeveloped acres held in the Bakken play in North Dakota and Montana, the Oklahoma Woodford play, and the Niobrara play in Colorado and Wyoming, we held 375,412 net undeveloped acres in other crude oil and natural gas plays as of December 31, 2012. Our technical staff is focused on identifying and testing new unconventional crude oil and natural gas resource plays where significant reserves could be developed if economically producible volumes can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

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Our Business Strengths

We have a number of strengths we believe will help us successfully execute our business strategy:

Large Acreage Inventory. We hold 1,347,046 net undeveloped acres and 897,542 net developed acres as of December 31, 2012. Approximately 72% of the net undeveloped acres are located within unconventional resource plays in the Bakken (North Dakota and Montana), Woodford (Oklahoma) and the Niobrara (Colorado and Wyoming). The remaining balance of the net undeveloped acreage is located in conventional plays including 3D-defined locations for the Lodgepole (North Dakota), Morrow-Springer (Western Oklahoma) and Frio (South Texas) plays.

Experience with Horizontal Drilling and Enhanced Recovery Methods. We have substantial experience with horizontal drilling and enhanced recovery methods. In 1992, we drilled our first horizontal well, and we have drilled over 1,800 horizontal wells since that time. We continue to be a leader in the development of new drilling and completion technologies. Our trademarked ECO-Pad drilling concept, which allows for drilling multiple wells from a single pad, is becoming a standard drilling approach in the industry because it improves land use and increases operating efficiencies. We started with drilling four wells per pad but have since begun drilling as many as 14 wells on a pad site. We are also on the leading edge of extending lateral drilling lengths, in some instances up to three miles. In 2012, we completed the first multiple-unit spaced well drilled in Oklahoma, which had a horizontal section that was twice the length of previous laterals in the area. Longer laterals are believed to have a positive impact on well productivity and economics. Additionally, we are pioneering the exploration and evaluation of the lower layers or benches of the Three Forks formation in the Bakken field, initially targeting the first bench of the Three Forks in mid-2008 followed by the successful completion of our first well in the second bench in October 2011. In 2012, we successfully completed the first well ever drilled in the third bench of the Three Forks, the discovery of which may lead to an increase in recoverable reserves for the Company and the Bakken field as a whole.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2012, we operated properties comprising 84% 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 crude oil and natural gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the crude oil and natural gas industry in 1967. Our 9 senior officers have an average of 29 years of crude oil and natural gas industry experience.

Strong Financial Position. We have a revolving credit facility with lender commitments totaling $1.5 billion and a borrowing base of $3.25 billion as of February 15, 2013, with available borrowing capacity of $655.2 million at that date after considering outstanding borrowings and letters of credit. While our current commitments total $1.5 billion, we have the ability to increase the aggregate commitment level up to the lesser of $2.5 billion or the borrowing base then in effect to provide additional available liquidity if needed to maintain our growth strategy, take advantage of business opportunities, and fund our capital program. We believe our planned exploration and development activities will be funded substantially from our operating cash flows and borrowings under our revolving credit facility. Our 2013 capital expenditures budget has been established based on our current expectation of available cash flows from operations and availability under our revolving credit facility. Should expected available cash flows from operations materially differ from expectations, we believe our credit facility has sufficient availability to fund any deficit or that we can reduce our capital expenditures to be in line with cash flows from operations.

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Crude Oil and Natural Gas Operations

Proved Reserves

Proved reserves are those quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain. The term reasonable certainty implies a high degree of confidence that the quantities of crude oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal reserve engineers and Ryder Scott, our independent reserve engineers, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, seismic data and well test data.

The following tables set forth our estimated proved crude oil and natural gas reserves and PV-10 by reserve category as of December 31, 2012. The total Standardized Measure of discounted cash flows as of December 31, 2012 is also presented. Ryder Scott evaluated properties representing approximately 99% of our PV-10, 99% of our proved crude oil reserves, and 96% of our proved natural gas reserves as of December 31, 2012, and our internal technical staff evaluated the remaining properties. A copy of Ryder Scott s summary report is included as an exhibit to this Annual Report on Form 10-K. Our estimated proved reserves and related future net revenues and PV-10 at December 31, 2012 were determined using the 12-month unweighted average of the first-day-of-the-month commodity prices for the period of January 2012 through December 2012, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $94.71 per Bbl for crude oil and $2.76 per MMBtu for natural gas ($86.56 per Bbl for crude oil and $4.31 per Mcf for natural gas adjusted for location and quality differentials).

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (1) (in millions)
Proved developed producing	220,392	531,776	309,021	$ 7,710.0
Proved developed non-producing	6,478	13,723	8,765	227.8
Proved undeveloped	334,293	795,585	466,891	5,371.1
Total proved reserves	561,163	1,341,084	784,677	$ 13,308.9
Standardized Measure				$ 11,180.4

(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. Standardized Measure at December 31, 2012 is $11.2 billion, a $2.1 billion difference from PV-10 because of the income tax effect. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the crude oil and natural gas 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 income tax characteristics of such entities.

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The following table provides additional information regarding our proved crude oil and natural gas reserves by region as of December 31, 2012.

	Proved Developed			Proved Undeveloped		
	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
North Region:						
Bakken field						
North Dakota Bakken	124,880	189,054	156,389	298,333	377,782	361,297
Montana Bakken	20,931	25,248	25,139	17,082	21,970	20,744
Red River units						
Cedar Hills	52,694	15,488	55,275	533		533
Other Red River units	19,094	355	19,153	3,292		3,292
Other	867	12,083	2,881	59	1,245	266
South Region:						
Oklahoma Woodford						
SCOOP	4,594	84,631	18,698	11,922	193,638	44,195
Northwest Cana	1,806	117,206	21,340	1,844	130,219	23,548
Arkoma Woodford	44	66,881	11,192	25	64,951	10,850
Other	1,960	34,553	7,719	1,203	5,780	2,166
Total	226,870	545,499	317,786	334,293	795,585	466,891

Reserves at December 31, 2010, 2011 and 2012 were computed using the 12-month unweighted average of the first-day-of-the-month commodity prices as required by SEC rules. Changes in proved reserves were as follows for the periods indicated:

	Year Ended December 31,		
MBoe	2012	2011	2010
Proved reserves at beginning of year	508,438	364,712	257,293
Revisions of previous estimates	4,149	2,237	27,629
Extensions, discoveries and other additions	233,652	161,981	95,233
Production	(35,716)	(22,581)	(15,811)
Sales of minerals in place	(7,838)		
Purchases of minerals in place	81,992	2,089	368
Proved reserves at end of year	784,677	508,438	364,712

Revisions. Revisions represent changes in previous reserve estimates, upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs, or development costs. Revisions for the year ended December 31, 2010 were due to better than anticipated production performance and higher average commodity prices throughout 2010 compared to 2009.

Extensions, discoveries and other additions. These are additions to our proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions for each of the three years reflected in the table above were primarily due to increases in proved reserves associated with our successful drilling activity and strong production growth in the Bakken field in North Dakota. In 2012, we continued to make significant headway in developing and expanding our North Dakota Bakken assets, both laterally and vertically, through strategic exploration, planning and technology. We expect a significant portion of future reserve additions will come from our major development projects in the Bakken, SCOOP and Northwest Cana plays.

Sales of minerals in place. These are reductions to proved reserves that result from the disposition of properties during a period. During the year ended December 31, 2012, we disposed of certain non-strategic properties in Oklahoma, Wyoming, and our East region in an effort to redeploy capital to our strategic areas that we believe will deliver higher future growth potential. See *Part II, Item 8. Notes to Consolidated Financial Statements Note 13. Property Acquisitions and Dispositions* for further discussion of our 2012 dispositions. We may continue to seek opportunities to sell non-strategic properties if and when we have the ability to dispose of such assets at favorable terms.

Purchases of minerals in place. These are additions to proved reserves that result from the acquisition of properties during a period. Purchases for the year ended December 31, 2012 primarily reflect the Company s acquisition of properties in the Bakken play of North Dakota during the year. See *Part II, Item 8. Notes to Consolidated Financial Statements Note 13. Property Acquisitions and Dispositions* and *Note 14. Property Transaction with Related Party* for further discussion of our 2012 acquisitions. We may continue to participate as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process. Ryder Scott, our independent reserves evaluation consulting firm, estimated, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC, 99% of our PV-10, 99% of our proved crude oil reserves, and 96% of our proved natural gas reserves as of December 31, 2012 included in this Annual Report on Form 10-K. The Ryder Scott technical personnel responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Refer to Exhibit 99 included with this Annual Report on Form 10-K for further discussion of the qualifications of Ryder Scott personnel.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. In the fourth quarter, our technical team is in contact regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott s preparation of the year-end reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a copy of the Ryder Scott reserve report is reviewed by our Audit Committee with representatives of Ryder Scott and by our internal technical staff before the information is filed with the SEC on Form 10-K. Additionally, certain members of our senior management review and approve the Ryder Scott reserve report and on a quarterly basis review any internally estimated significant changes to our proved reserves.

Our Vice President Resource Development is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering, an MBA in Finance and 27 years of industry experience with positions of increasing responsibility in operations, acquisitions, engineering and evaluations. He has worked in the area of reserves and reservoir engineering most of his career and is a member of the Society of Petroleum Engineers. The Vice President Resource Development reports directly to our Senior Vice President Operations and Resource Development. The reserve estimates are reviewed and approved by the President and Chief Operating Officer and certain other members of senior management.

Proved Undeveloped Reserves. Our proved undeveloped reserves at December 31, 2012 were 466,891 MBoe, consisting of 334,293 MBbls of crude oil and 795,585 MMcf of natural gas. In 2012, we developed approximately 17% of our proved undeveloped reserves booked as of December 31, 2011 through the drilling of 231 gross (127.9 net) development wells at an aggregate capital cost of approximately $892 million. Also in

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2012, we removed 202 gross (90.0 net) PUD locations, which resulted in the removal of 3.5 MMBo and 183.8 Bcf (34.2 MMBoe) of proved undeveloped reserves. These removals were predominantly due to our decision to declassify 100.4 Bcf (16.7 MMBoe) of proved undeveloped reserves in our Arkoma Woodford district, which consists primarily of dry gas. For similar reasons, we removed 1.4 MMBo and 73.3 Bcf (13.6 MMBoe) of proved undeveloped reserves in our Northwest Cana district. Given current and projected prices for natural gas, we elected to defer drilling and as a result declassified these proved undeveloped reserves accordingly. Estimated future development costs relating to the development of proved undeveloped reserves are projected to be approximately $1.8 billion in 2013, $2.2 billion in 2014, $2.0 billion in 2015, $1.4 billion in 2016, and $0.9 billion in 2017.

Since our entry into the Bakken field, we have acquired a substantial leasehold position. Our drilling programs to date have focused on proving our undeveloped leasehold acreage through strategic exploratory drilling, thereby increasing the amount of leasehold acreage in the secondary term of the lease with no further drilling obligations (i.e., categorized as held by production) and resulting in a reduced amount of leasehold acreage in the primary term of the lease with drilling obligations. While we will continue to drill strategic exploratory wells and build on our current leasehold position, we expect to increase our focus on developing our PUD locations. While full development of our current PUD inventory is expected to occur within five years, we believe additional PUD locations will be generated through drilling activities.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acres by region as of December 31, 2012:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	758,998	473,068	619,786	393,899	1,378,784	866,967
Montana Bakken	127,276	107,053	219,029	165,783	346,305	272,836
Red River units	150,450	135,483			150,450	135,483
Niobrara - Colorado/Wyoming	11,271	7,726	183,985	103,585	195,256	111,311
Other	22,427	8,491	191,916	104,741	214,343	113,232
South Region:						
Oklahoma Woodford						
SCOOP	33,023	21,995	379,793	196,172	412,816	218,167
Northwest Cana	115,742	71,539	156,001	106,893	271,743	178,432
Arkoma Woodford	107,402	26,291	12,064	5,302	119,466	31,593
Other	96,803	45,896	115,169	80,197	211,972	126,093
East Region			210,742	190,474	210,742	190,474
Total	1,423,392	897,542	2,088,485	1,347,046	3,511,877	2,244,588

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The following table sets forth the number of gross and net undeveloped acres as of December 31, 2012 that are expected to expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	245,602	114,101	116,545	63,992	108,842	71,683
Montana Bakken	71,494	45,749	72,244	59,083	39,654	33,964
Red River units						
Niobrara - Colorado/Wyoming	46,283	27,253	16,740	10,823	100,981	52,531
Other	57,785	37,423	5,740	3,253	14,120	8,981
South Region:						
Oklahoma Woodford						
SCOOP	63,855	33,816	118,772	67,201	76,917	44,602
Northwest Cana	93,126	60,844	28,395	20,987	11,917	8,697
Arkoma Woodford	7,762	4,763	270	121		
Other	5,101	3,604	2,198	1,294	71,123	49,265
East Region	41,196	32,446	9,704	7,543	14,188	9,763
Total	632,204	359,999	370,608	234,297	437,742	279,486

Drilling Activity

During the three years ended December 31, 2012, we drilled exploratory and development wells as set forth in the table below:

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	76	37.0	50	23.4	42	11.8
Natural gas	78	43.8	109	45.9	25	10.9
Dry holes	1	1.0	2	1.3	4	2.2
Total exploratory wells	155	81.8	161	70.6	71	24.9
Development wells:						
Crude oil	561	211.3	380	126.1	231	91.5
Natural gas	5	2.4	17	1.6	44	5.2
Dry holes	3	1.1	5	0.6	3	1.0
Total development wells	569	214.8	402	128.3	278	97.7
Total wells	724	296.6	563	198.9	349	122.6

As of December 31, 2012, there were 323 gross (122.4 net) wells in the process of drilling, completing or waiting on completion.

As of February 15, 2013, we operated 28 rigs on our properties. Our rig activity during 2013 will depend on potential drilling efficiency gains and crude oil and natural gas prices and, accordingly, our rig count may increase or decrease from current levels. There can be no assurance, however, that additional rigs will be available to us at an attractive cost. See *Part I, Item 1A. 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 budget and on a timely basis.*

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Summary of Crude Oil and Natural Gas Properties and Projects

Throughout the following discussion, we discuss our budgeted number of wells and capital expenditures for 2013. Although we cannot provide any assurance, we believe our cash flows from operations, remaining cash balance, and our revolving credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to satisfy our 2013 capital budget. We may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, available cash flows, unbudgeted acquisitions, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. Further, a decline in commodity prices could cause us to curtail our actual capital expenditures. Conversely, an increase in commodity prices could result in increased capital expenditures.

As referred to throughout this report, a play is a term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves. Conventional plays are areas believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps. Unconventional plays are areas believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but require recently developed technologies to achieve profitability. Unconventional plays tend to have low permeability and may be closely associated with source rock as is the case with oil and gas shale, tight oil and gas sands and coalbed methane. Our operations in unconventional plays include operations in the Bakken and Woodford plays and the Red River units. Our operations within conventional plays include operations in the Lodgepole of North Dakota, Morrow-Springer of western Oklahoma and Frio in south Texas. In general, unconventional plays require the application of more advanced technology and higher drilling and completion costs to produce relative to conventional plays. These technologies can include hydraulic fracturing treatments, horizontal wellbores, multilateral wellbores, or some other technique or combination of techniques to expose more of the reservoir to the wellbore.

References throughout this report to 3D seismic refer to seismic surveys of areas by means of an instrument which records the travel time of vibrations sent through the earth and the interpretation thereof. By recording the time interval between the source of the shock wave and the reflected or refracted shock waves from various formations, geophysicists are better able to define the underground configurations. 3D defined locations are those locations that have been subjected to 3D seismic testing. We typically use 3D seismic testing to evaluate reservoir presence and/or continuity. We do not typically evaluate reservoir productivity using 3D seismic technology.

North Region

Our properties in the North region represented 90% of our PV-10 as of December 31, 2012 and 78% of our average daily Boe production for the three months ended December 31, 2012. For the three months ended December 31, 2012, our average daily production from such properties was 83,205 Boe per day, an increase of 45% over our average daily production for the three months ended December 31, 2011. Our principal producing properties in the North region are in the Bakken field and the Red River units.

Bakken Field

The Bakken field of North Dakota and Montana is one of the premier crude oil resource plays in the United States. It has been described by the United States Geological Survey (USGS) as the largest continuous crude oil accumulation it has ever assessed. Estimates of recoverable reserves for the Bakken field have grown from 4.3 billion barrels of crude oil, as published in a report issued by the USGS in April 2008, to potentially 11 billion barrels of crude oil in North Dakota alone, as reported by the North Dakota Industrial Commission (NDIC) in January 2011. In October 2011, the USGS began a study to update their 2008 assessment of recoverable reserves for the Bakken field to include reserves from the Three Forks formation and take into account improved well performance due to advances in drilling, completion and production technologies. Results of the USGS study may be announced in late 2013.

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Industry-wide production from the Bakken field reached a record 801,500 Boe per day in October 2012, up 55% over October 2011 based on data published by IHS Inc. Industry-wide drilling activity in the Bakken field also reached record levels at 229 rigs in June 2012. North Dakota now ranks as the second largest crude oil producing state in the U.S. due to production growth in the Bakken field. We continue to be a leader in the development and expansion of the Bakken field and control the largest leasehold position with approximately 1,725,089 gross (1,139,803 net) acres as of December 31, 2012. We are also the most active driller in the Bakken field, with 21 operated rigs drilling as of February 15, 2013. During 2012, we completed 573 gross (204.1 net) wells in the Bakken field. Our properties within the Bakken field represented 74% of our PV-10 as of December 31, 2012 and 63% of our average daily Boe production for the three months ended December 31, 2012. As of December 31, 2012 we had completed 1,887 gross (757.7 net) wells in the Bakken field. Our inventory of proved undeveloped drilling locations in the Bakken field as of December 31, 2012 totaled 1,501 gross (847.3 net) wells.

During 2012, we saw our production, reserves and acreage position in the Bakken field grow while substantial portions of our undeveloped acreage continued to be de-risked due to the record levels of drilling activity in North Dakota. Our Bakken field production averaged 67,522 Boe per day during the three months ended December 31, 2012, up 64% from our average daily Bakken field production for the three months ended December 31, 2011. Our total proved Bakken field reserves at December 31, 2012 were 564 MMBoe, up 92% over our proved Bakken field reserves as of December 31, 2011.

Our development drilling activity accelerated in 2012 since much of the Bakken field is now entering the development mode. This allowed us to increase the use of our ECO-Pad technology in 2012. Using ECO-Pad technology allows us to utilize more efficient centralized production facilities that accelerate production and reduce the environmental footprint of our operations. Combined, we expect these efficiencies will result in reduced costs for wells drilled from ECO-Pads. Approximately 18% of our operated wells completed in 2012 were drilled from ECO-Pads. At February 15, 2013, 67% of our 21 operated rigs in the Bakken were capable of ECO-Pad drilling and 14 rigs were actively drilling pad locations.

We strengthened our Bakken focus in 2012 by executing strategic property acquisitions throughout the year, which allowed us to increase our ownership in existing and future operated and non-operated wells in the play. We believe the acquisitions will allow us to leverage the scale and efficiency of our Bakken operations to help lower our drilling and completion costs. As a result of our leasing and acquisition activities, we increased our net acreage position in the Bakken field by 24% during 2012, from 915,863 net acres as of December 31, 2011 to 1,139,803 net acres as of December 31, 2012. Approximately 51% of our net acreage in the Bakken field is developed and the remaining 49% of our net acreage is undeveloped as of December 31, 2012.

We plan to invest approximately $2.4 billion drilling 558 gross (226.2 net) wells in the Bakken field during 2013, of which approximately 83% will be invested in North Dakota and the remaining 17% will be invested in Montana. We plan to average 22 rigs drilling in the Bakken field throughout the year, with 17 rigs located in North Dakota and 5 rigs in Montana.

North Dakota Bakken. Our production and reserve growth in the Bakken field during 2012 came primarily from our activities in North Dakota. Production increased to an average rate of 59,019 Boe per day during the three months ended December 31, 2012, up 66% from the average daily rate for the three months ended December 31, 2011. Proved reserves grew 102% year-over-year to 518 MMBoe as of December 31, 2012. As of December 31, 2012, our North Dakota Bakken properties represented 67% of our PV-10 and 55% of our average daily Boe production for the three months ended December 31, 2012. We completed 526 gross (173.0 net) wells during 2012, bringing our total number of wells drilled in the North Dakota Bakken to 1,589 gross (576.5 net) as of December 31, 2012. As of December 31, 2012, we had 1,378,784 gross (866,967 net) acres in the North Dakota Bakken field, of which 55% of the net acreage is developed and 45% of the net acreage is undeveloped. Our inventory of proved undeveloped locations stood at 1,421 gross (791.3 net) wells as of December 31, 2012.

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Our drilling activity in the North Dakota Bakken field during 2012 was diversified, reflecting the extensive nature of our acreage position. With 866,967 net acres in the North Dakota Bakken as of December 31, 2012, some areas of the field were under development while other areas were being tested through step-out and exploratory drilling. All combined, in 2012 we made significant progress in developing and expanding our North Dakota Bakken assets through strategic exploration, planning and technology.

During 2012, we expanded the known productive extents of the Bakken field laterally and vertically through strategic step-out and exploratory drilling. Our step-out drilling continued to expand the productive footprint of the field west and east of the Nesson anticline. Of particular significance to the Company and the Bakken field in general during 2012 was our ongoing exploration efforts to evaluate the Lower Three Forks formation. Through our independent coring program, we discovered there were three additional layers or benches of crude oil bearing reservoir rock in the Lower Three Forks formation. We refer to these three benches as the second, third and fourth benches of the Three Forks formation (TF2 , TF3 and TF4 , respectively) and they are located approximately 50 to 150 feet below the traditional Middle Bakken (MB) and Upper Thre Forks (TF1) reservoirs. This discovery redefined the Bakken petroleum system and prompted the NDIC to expand the definition of the Bakken reservoir to include all zones from 50 feet above the top of the Bakken formation down to the base of the Three Forks formation across much of the Bakken field in North Dakota.

The discovery of three additional benches indicates the Lower Three Forks formation has the potential to add incremental reserves in the Bakken field. The existence of more reserves in place could potentially translate into an increase in recoverable reserves for the Company and the Bakken field as a whole. To determine if there are incremental reserves to be recovered from the Lower Three Forks formation, we have begun drilling wells to test the TF2, TF3 and TF4 reservoirs. In October 2011, we successfully completed our first well in the TF2. The Charlotte 2-22H was completed flowing 1,396 Boe per day from the TF2 and as of February 15, 2013 the well had produced 107 MBoe and continues to produce in line with a typical commercial TF1 producing well. In November 2012, we successfully completed the first well ever drilled in the TF3. The Charlotte 3-22H was completed flowing 953 Boe per day from the TF3 and as of February 15, 2013 had produced 33 MBoe and continues to produce in line with a typical commercial TF1 producing well. In 2013, we plan to drill 20 gross (15.2 net) strategically placed wells throughout our Bakken acreage to accelerate our assessment of the Lower Three Forks reservoirs.

During 2013, we plan to invest approximately $2.0 billion drilling 507 gross (185.2 net) wells in the North Dakota Bakken field. Approximately 18% of the capital expenditures are expected to be spent on exploratory drilling to test the lower benches of the Three Forks formation and conduct multi-zone pilot development projects. These pilot development projects will test the viability of developing four reservoirs (MB, TF1, TF2, and TF3) on 320-acre and 160-acre spacing. The remainder of the capital expenditures are expected to be spent on drilling development and step-out wells in the field. As of February 15, 2013, we had 16 operated rigs drilling in the North Dakota Bakken and plan to operate 17 rigs drilling in the play through most of 2013.

Montana Bakken. Our Montana Bakken properties are located primarily in the Elm Coulee field in Richland County, Montana. The Elm Coulee field was listed by the Energy Information Administration (EIA) in 2010 as the 17th largest onshore field in the lower 48 states of the United States ranked by 2009 proved liquid reserves. During 2012, we completed 47 gross (31.0 net) wells, bringing our total number of wells drilled in the Montana Bakken to 298 gross (181.2 net) wells as of December 31, 2012. Our production increased to an average rate of 8,503 Boe per day for the three months ended December 31, 2012, up 50% from the average daily rate for the three months ended December 31, 2011. As of December 31, 2012 our Montana Bakken properties represented 7% of our PV-10 and 8% of our average daily Boe production for the three months ended December 31, 2012. As of December 31, 2012, we owned 346,305 gross (272,836 net) acres in Montana Bakken, of which 39% of the net acreage is developed and the remaining 61% of the net acreage is undeveloped.

In 2012, we continued to expand the proven extents of the Elm Coulee field using state of the art drilling and completion technology. Areas once considered non-commercial based on old open hole completion technology

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have now proven to be commercial using cased hole, multi-stage fracture stimulation technology. During 2012, our well completions in the immediate Elm Coulee field area included in-field, step-out and strategic exploratory wells that were completed flowing at initial 24 hour rates of up to 1,301 Boe per day. Based on our 2012 drilling program, the productive limits of the Elm Coulee field were expanded up to approximately 10 miles to the north onto portions of our undeveloped leasehold.

We plan to invest approximately $426 million drilling 51 gross (41.0 net) wells in the Montana Bakken during 2013. Our drilling will focus on in-field development and continued expansion of the Elm Coulee field onto our undeveloped acreage north of the field. As of February 15, 2013, we had 5 rigs drilling in the Montana Bakken and plan to maintain 5 rigs in the play through most of 2013. As of December 31, 2012, we had 80 gross (55.9 net) proved undeveloped locations identified in the Montana Bakken.

Red River Units

The Red River units are comprised of eight units located along the Cedar Creek Anticline in North Dakota, South Dakota and Montana that produce crude 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 principal producing properties in the Red River units include the Cedar Hills units in North Dakota and Montana, the Medicine Pole Hills units in North Dakota, and the Buffalo Red River units in South Dakota. Our properties in the Red River units comprise a portion of the Cedar Hills field, which was listed by the EIA in 2010 as the 9th largest onshore field in the lower 48 states of the United States ranked by 2009 proved liquid reserves.

All combined, our Red River units represented 15% of our PV-10 as of December 31, 2012 and 14% of our average daily Boe production for the three months ended December 2012. Production from these legacy properties increased 4% in 2012 compared to 2011 due to new wells being completed and enhanced recovery techniques being successfully applied. Proved reserves grew 22% year-over-year to 78 MMBoe as of December 31, 2012. We are continuing to extend the peak performance life of our properties in the Red River units primarily by increasing our water and air injection capabilities and taking other measures to optimize production. As of December 31, 2012, we had 150,450 gross (135,483 net) acres in the Red River units, all of which is developed acreage.

We have allocated $63 million of our 2013 capital expenditure budget to the Red River units, which will support one drilling rig and continued investment in facilities and infrastructure.

North Region Marketing Activities

Crude Oil. We are building upon a portfolio approach to marketing our crude oil that began in 2008 with our first shipments of crude oil by rail out of the Williston Basin. During 2012, we accessed new market centers on the east and west coasts of the United States and expanded our marketing efforts along the U.S. gulf coast. This approach has provided flexibility to allow us to shift sales of our North region crude oil to markets that provide the most favorable pricing. During 2012, we moved from predominantly using pipelines to deliver our North region crude oil to traditional market centers in Guernsey, Wyoming and Clearbrook, Minnesota to using rail deliveries into U.S. coastal markets that yield superior pricing compared to the unstable mid-continent market centers.

Rail transportation costs are typically higher than pipeline transportation costs per barrel mile; however, the premium received for our North region production being sold at Brent-based prices in U.S. coastal markets compared to mid-continent West Texas Intermediate (WTI) benchmark pricing has more than offset the increased transportation costs. We expect that rail transportation will take a prominent role in crude oil deliveries out of the North region throughout 2013 and then may lessen in significance as additional pipeline infrastructure is built out of the Williston Basin to the great lakes, upper mid-west, southern mid-continent and gulf coast regions of the United States. We expect rail transportation costs will then be impacted by pressure to compete with pipeline economics.

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We anticipate volatility in price differentials between the mid-continent and coastal markets will continue through 2013 as infrastructure is built out and refiners establish a desire for the high quality grade of Bakken crude oil. We believe the Bakken field contains superior quality crude oil with ample supply and volume growth to meet refiners needs for years to come.

Transportation infrastructure continues to improve in the North region with gathering systems picking up crude oil at well site storage tanks with subsequent delivery to railhead or regional pipeline terminals, thereby mitigating the need for truck deliveries. We expect more of our North region crude oil will be shipped in this fashion through the coming years, especially as we accelerate development drilling using ECO-Pad technology.

Natural Gas. Field infrastructure build-out continued at a rapid pace in the Williston Basin in 2012 as third party midstream gathering and processing companies expanded field gathering and compression facilities, cryogenic processing capacity and natural gas liquids (NGL) pipeline and rail capacity to market centers. Aided by improved infrastructure, we reduced the percentage of our operated natural gas production being flared in North Dakota Bakken by approximately 50% in 2012. During December 2012, we flared approximately 10% of produced natural gas volumes on our operated North Dakota Bakken wells and expect to further reduce this amount as we continue to build out infrastructure and transition to a greater use of ECO-Pad development in 2013 and beyond.

South Region

Our properties in the South region represented 10% of our PV-10 as of December 31, 2012 and 21% of our average daily Boe production for the three months ended December 31, 2012. For the three months ended December 31, 2012, our average daily production from such properties was 22,620 Boe per day, up 36% from the same period in 2011. Our principal producing properties in this region are located in the Anadarko and Arkoma basins of Oklahoma, as well as various basins in Texas and Louisiana.

Oklahoma Woodford Shale

The Oklahoma Woodford is a widespread unconventional shale reservoir that produces crude oil, natural gas and natural gas condensate in various basins across the state of Oklahoma. Our principal producing properties in the Oklahoma Woodford are located in the Anadarko and Arkoma basins. Combined, these properties represented 9% of our PV-10 as of December 31, 2012 and 19% of our average daily Boe production for the three months ended December 31, 2012. Production from the Oklahoma Woodford for 2012 totaled 7,099 MBoe, up 100% over 2011. Average daily production for our Oklahoma Woodford properties for the three months ended December 31, 2012 was 20,064 Boe per day, up 49% over our average daily production for the three months ended December 31, 2011. As of December 31, 2012, we held 804,025 gross (428,192 net) acres in the Oklahoma Woodford. As of December 2012, 28% of the net acreage is developed and the remaining 72% of the net acreage is undeveloped.

During 2012, we completed 93 gross (48.7 net) Oklahoma Woodford wells. During 2013, we plan to invest approximately $455 million drilling 92 gross (41.9 net) wells in the Oklahoma Woodford. As of February 15, 2013 we had 6 rigs drilling in the Oklahoma Woodford and plan to operate an average of 9 rigs in the play through most of 2013.

In 2012, we divided our Anadarko Woodford assets into two projects we refer to as SCOOP and Northwest Cana. Our wells in the SCOOP area typically produce significantly more crude oil and natural gas liquids than wells in Northwest Cana and provide a higher rate of return on the dollars we invest. Consequently, our drilling and development plans for SCOOP differ from our plans for Northwest Cana. As a result, we now report and discuss the two areas separately. The difference between the SCOOP and Northwest Cana areas is rooted in our geologic model that determined the SCOOP area is ideally suited for crude oil and liquids rich production from the Woodford reservoir. Due to the depositional, tectonic and thermal history of the SCOOP area, we believe it contains some of the best and thickest Woodford reservoir rocks in Oklahoma. The Woodford formation is

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thought to be the source of much of the crude oil produced from over 60 different conventional reservoirs in Oklahoma since the early 1900s. Three of the largest crude oil producing counties in Oklahoma are located in the SCOOP play.

SCOOP

Our SCOOP properties are located in southern Oklahoma primarily in Garvin, Grady, Stephens, Carter, McClain and Love Counties. SCOOP represented 7% of our PV-10 as of December 31, 2012 and 7% of our average daily Boe production for the three months ended December 31, 2012. For the year ended December 31, 2012, SCOOP production grew 297% over 2011 due to our increased drilling activity. For the three months ended December 31, 2012, SCOOP production averaged 7,123 Boe per day, up 281% over our average daily production for the three months ended December 31, 2011. As of December 31, 2012 we held 412,816 gross (218,167 net) acres under lease in SCOOP. As of December 31, 2012, 10% of the net acreage is developed and the remaining 90% of the net acreage is undeveloped. Our inventory of proved undeveloped drilling locations in SCOOP as of December 31, 2012 totaled 122 gross (58.4 net) wells.

We completed 47 gross (24.8 net) wells in SCOOP during 2012 and as of December 31, 2012 we had completed a total of 68 gross (37.2 net) wells in SCOOP. Although SCOOP is in the early stages of development, industry-wide drilling results through December 31, 2012 have established a crude oil producing fairway and a condensate rich, natural gas producing fairway that combined is approximately 15 to 20 miles wide and 120 miles long. Our internal reserve models estimate wells in the SCOOP crude oil fairway may produce approximately 626 MBoe per well and wells in the SCOOP s condensate rich natural gas fairway may produce approximately 1,190 MBoe per well. The SCOOP area could prove to be another significant opportunity for reserve and production growth for the Company.

A possible upside to SCOOP is the potential to encounter additional pay from a variety of conventional and potential unconventional reservoirs overlying and underlying the Woodford formation. There are over 60 different conventional reservoirs known to produce in the SCOOP area. These conventional reservoirs have the potential to produce locally under our SCOOP acreage.

In 2013, we plan to invest approximately $450 million to drill 90 gross (40.5 net) wells in the SCOOP play. We also expect to invest approximately $9 million to acquire 103 square miles of additional proprietary 3D seismic data to guide future drilling. As of February 15, 2013, we had 6 operated rigs drilling in the SCOOP. We plan to add rigs throughout the year targeting 12 rigs by December 2013 with an expected average rig count of 9 for 2013.

Northwest Cana

Our Northwest Cana properties are located in northwestern Oklahoma primarily in Blaine, Dewey and Custer Counties. Northwest Cana represented 2% of our PV-10 as of December 31, 2012 and 9% of our average daily Boe production for the three months ended December 31, 2012. For the year ended December 31, 2012, Northwest Cana production grew 134% over 2011 due to our increased drilling activity. For the three months ended December 31, 2012, Northwest Cana production averaged 9,716 Boe per day, up 22% over our average daily production for the three months ended December 31, 2011. As of December 31, 2012 we held 271,743 gross (178,432 net) acres under lease in Northwest Cana. As of December 31, 2012, 40% of the net acreage is developed and the remaining 60% of the net acreage is undeveloped. During 2012, we completed 43 gross (22.8 net) wells in Northwest Cana and as of December 31, 2012 we had completed a total of 161 gross (73.3 net) wells in Northwest Cana. We had a total of 90 gross (38.6 net) proved undeveloped locations on our Northwest Cana acreage as of December 31, 2012. No significant drilling or development plans are expected to take place in the Northwest Cana play in 2013 due to the pricing environment for natural gas.

Arkoma Woodford

The Arkoma Woodford represented less than 1% of our PV-10 as of December 31, 2012 and 3% of our average daily Boe production for the three months ended December 31, 2012. Year-over-year, Arkoma Woodford production decreased 2% due to the suspension of our drilling program in 2012 due to the pricing environment for natural gas. In 2012, we completed 3 gross (1.1 net) wells, compared to 18 gross (4.8 net) wells in 2011. As of December 31, 2012 we had completed a total of 395 gross (59.6 net) wells in the Arkoma Woodford play. As of December 31, 2012, we held 119,466 gross (31,593 net) acres under lease in the Arkoma Woodford play. Approximately 83% of our net acreage is developed and the remaining 17% of our net acreage is undeveloped as of December 31, 2012. We had a total of 22 gross (15.2 net) proved undeveloped locations in the Arkoma Woodford as of December 31, 2012. In 2013, we do not plan on drilling any new wells in the play.

South Region Marketing Activities

Crude Oil. Due to the proximity of our South region operations to the market center in Cushing, Oklahoma, we typically sell our South region production directly to midstream trading and transportation companies at the wellhead with price realizations that correlate with WTI benchmark pricing. We anticipate continuing this approach through early 2013 and to begin delivery of production from our SCOOP properties via wellhead pipeline gathering systems directly into Cushing as field infrastructure is constructed and developed.

During 2013, we expect the disparity of WTI pricing to Brent pricing will begin to improve as the recently expanded Seaway Pipeline begins to alleviate the oversupply of crude oil at Cushing and as Permian Basin production begins to take newly-developed routes to gulf coast market centers that do not go to or through Cushing.

Natural Gas. In 2012, field infrastructure build-out continued at a rapid pace in the Anadarko Basin and in SCOOP as third party midstream gathering and processing companies expanded field gathering and compression facilities, cryogenic processing capacity and NGL pipeline capacity to market centers. Throughout our South region leasehold, we are coordinating our well completion operations to coincide with well connections to gathering systems in order to minimize greenhouse gas emissions.

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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, 2012, 2011 and 2010 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2012:

	Year Ended December 31,		
	2012	2011	2010
Net production volumes:			
Crude oil (MBbls) (1)			
North Dakota Bakken	15,936	8,480	4,450
Total Company	25,070	16,469	11,820
Natural gas (MMcf)			
North Dakota Bakken	16,454	7,523	3,994
Total Company	63,875	36,671	23,943
Crude oil equivalents (MBoe)			
North Dakota Bakken	18,679	9,733	5,116
Total Company	35,716	22,581	15,811
Average sales prices: (2)			
Crude oil ($/Bbl)			
North Dakota Bakken	$ 84.50	$ 88.43	$ 70.09
Total Company	84.59	88.51	70.69
Natural gas ($/Mcf)			
North Dakota Bakken	5.55	7.18	6.38
Total Company	4.20	5.24	4.49
Crude oil equivalents ($/Boe)			
North Dakota Bakken	76.95	82.56	65.94
Total Company	66.83	73.05	59.70
Average costs per Boe: (2)			
Production expenses ($/Boe)			
North Dakota Bakken	$ 4.31	$ 4.05	$ 2.94
Total Company	5.49	6.13	5.87
Production taxes and other expenses ($/Boe)	6.42	6.42	4.82
General and administrative expenses ($/Boe) (3)	3.42	3.23	3.09
DD&A expense ($/Boe)	19.44	17.33	15.33

(1) Crude oil sales volumes differ from production volumes because, at various times, we have stored crude oil in inventory due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. Crude oil sales volumes were 112 MBbls less than production volumes for the year ended December 31, 2012, 30 MBbls less than production volumes for the year ended December 31, 2011 and 78 MBbls more than production volumes for the year ended December 31, 2010.

(2) Average sales prices and per unit costs have been calculated using sales volumes and exclude any effect of derivative transactions.

(3) General and administrative expense ($/Boe) includes non-cash equity compensation expenses of $0.82 per Boe, $0.73 per Boe, and $0.74 per Boe for the years ended December 31, 2012, 2011 and 2010, respectively, and corporate relocation expenses of $0.22 per Boe and $0.14 per Boe for the years ended December 31, 2012 and 2011, respectively. No corporate relocation expenses were incurred in 2010.

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The following table sets forth information regarding our average daily production by region during the fourth quarter of 2012:

	Fourth Quarter 2012 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken field			
North Dakota Bakken	49,947	54,432	59,019
Montana Bakken	7,368	6,811	8,503
Red River units			
Cedar Hills	10,638	2,519	11,058
Other Red River units	3,189	2,812	3,658
Other	377	3,542	967
South Region:			
Oklahoma Woodford			
SCOOP	2,280	29,056	7,123
Northwest Cana	902	52,886	9,716
Arkoma Woodford	14	19,265	3,225
Other	735	10,921	2,556
East Region	999	45	1,006
Total	76,449	182,289	106,831

Productive Wells

Gross wells represent the number of wells in which we own a working interest and net wells represent the total of our fractional working interests owned in gross wells. The following table presents the total gross and net productive wells by region and by crude oil or natural gas completion as of December 31, 2012:

	Crude Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	1,466	493	6	1	1,472	494
Montana Bakken	265	175	2	1	267	176
Red River units	286	258	2	2	288	260
Other	16	9	5	2	21	11
South Region:						
Oklahoma Woodford						
SCOOP	19	8	44	26	63	34
Northwest Cana	9	5	151	68	160	73
Arkoma Woodford	1		394	60	395	60
Other	211	165	243	121	454	286
Total	2,273	1,113	847	281	3,120	1,394

As of December 31, 2012, we did not own interests in any wells containing multiple completions.

Title to Properties

As is customary in the crude oil and natural gas industry, contract landmen conduct a title examination of courthouse records upon acquisition of undeveloped leaseholds which do not have proved reserves. Such title examinations are reviewed by Company landmen. Prior to the commencement of drilling operations on those properties, we procure a title opinion from external legal counsel and perform curative work necessary to satisfy requirements pertaining to material title defects. We generally will not commence drilling operations on a

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property until we have cured material title defects on such property. We have procured title opinions on substantially all of our producing properties and believe we have defensible title to our producing properties in accordance with standards generally accepted in the crude oil and natural gas industry. Prior to completing an acquisition of producing crude oil and natural gas leases, Company and contract landmen perform title examinations at applicable courthouses and examine the seller s internal land/legal records including existing title opinions. We may procure a title opinion depending on the materiality of the properties involved. Our crude oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our revolving credit facility, and other burdens which we believe do not materially interfere with the use of the properties or affect our carrying value of such properties.

Marketing and Major Customers

Most of our crude oil production is sold to end users at major market centers. Other production not sold at major market centers is sold to select midstream marketing companies or crude oil refining companies at the lease. We have significant production directly connected to pipeline gathering systems, with the remaining balance of our production being transported by truck or rail. Where directly marketed crude oil is transported by truck, it is delivered to the most practical point on a pipeline system for delivery to a sales point downstream on another connecting pipeline. Crude oil sold at the lease is delivered directly onto the purchaser s truck and the sale is complete at that point.

As a result of pipeline constraints, the continuous increase in Williston Basin production, and our desire to transport our crude oil to coastal markets which currently provide the most favorable pricing, in December 2012 we transported approximately 72% of our operated crude oil production from the Bakken field by rail. We are using both manifest and unit train facilities for these shipments and anticipate these shipments will continue.

We have a strategic mix of gas transport, processing and sales arrangements for our natural gas production. Our natural gas production is sold at various points along the market chain from wellhead to points downstream under monthly interruptible packaged-volume deals, short-term seasonal packages, and long-term multi-year acreage dedication type contracts. All of our natural gas is sold at market. Some of our contracts allow us the flexibility to sell at the well or, with notice, take our gas in-kind , transport, process, and sell in the market area. Midstream natural gas gathering and processing companies are our primary transporters and purchasers.

Our marketing of crude 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 *Part I, Item 1A. Risk factors Our business depends on crude oil and natural gas transportation facilities, most of which are owned by third parties, and on the availability of rail transportation.*

For the years ended December 31, 2012, 2011 and 2010, crude oil sales to Marathon Crude Oil Company accounted for approximately 21%, 41% and 57% of our total crude oil and natural gas revenues, respectively. Additionally, crude oil sales to United Energy Trading accounted for approximately 11% of our total crude oil and natural gas revenues for the year ended December 31, 2012. No other purchasers accounted for more than 10% of our total crude oil and natural gas revenues for 2012, 2011 and 2010. We believe the loss of our largest purchaser would not have a material adverse effect on our operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in our producing regions.

Competition

We operate in a highly competitive environment for acquiring properties, marketing crude oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources 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 crude 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

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high cost of drilling rigs, equipment or other services 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.

Regulation of the Crude Oil and Natural Gas Industry

All of our operations are conducted onshore in the United States. The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. Laws, rules, regulations, policies, and interpretations affecting the crude oil and natural gas industry have been pervasive and are continuously reviewed by legislators and regulators, including the imposition of new or increased requirements on us and other industry participants. Applicable laws and regulations and other requirements affecting our industry and its members often carry substantial penalties for failure to comply. Such requirements may have a significant effect on the exploration, development, production and sale of crude oil and natural gas. These requirements increase the cost of doing business and, consequently, affect profitability. We believe we are in substantial compliance with all laws and regulations and policies currently applicable to our operations and our continued compliance with existing requirements will not have a material adverse impact on us. However, because public policy changes affecting the crude oil and natural gas industry are commonplace and because laws and regulations may be amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws and regulations. We do not expect any future legislative or regulatory initiatives will affect our operations in a manner materially different than they would affect our similarly situated competitors.

Following is a discussion of significant laws and regulations that may affect us in the areas in which we operate.

Regulation of Sales and Transportation of Crude Oil and Natural Gas Liquids

Sales of crude oil and natural gas liquids or condensate in the United States are not currently regulated and are made at negotiated prices. Nevertheless, the U.S. Congress could enact price controls in the future. The United States does regulate the exportation of petroleum and petroleum products, and these regulations could restrict the markets for these commodities and thus affect sales prices. With regard to our physical sales of crude oil and derivative instruments relating to crude oil, we are required to comply with anti-market manipulation laws and related regulations enforced by the Federal Trade Commission (FTC) and the Commodity Futures Trading Commission (CFTC). See the discussion below of Other Federal Laws and Regulations Affecting Our Industry. Should we violate the anti-market manipulation laws and regulations, we could be subject to substantial penalties and related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Our sales of crude oil are affected by the availability, terms and costs of transportation. The transportation of crude oil and NGLs, as well as other liquid products, is subject to rate and access regulation. The Federal Energy Regulatory Commission (FERC) regulates interstate crude oil and NGL pipeline transportation rates under the Interstate Commerce Act and the Energy Policy Act of 1992. In general, such pipeline rates must be cost-based, although many pipeline charges today are based on historical rates adjusted for inflation and other factors, and other charges may result from settlement rates agreed to by all shippers or market-based rates, which are permitted in certain circumstances. Intrastate crude oil and NGL pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state. Insofar as the interstate and intrastate transportation rates we pay are generally applicable to all comparable shippers, we believe the regulation of intrastate transportation rates will not affect our operations in a way that materially differs from the effect on the operations of our competitors who are similarly situated.

Further, interstate pipelines and intrastate common carrier pipelines must provide service on an equitable basis. Under this standard, such pipelines must offer service to all similarly situated shippers requesting service on the

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same terms and under the same rates. When such pipelines operate at full capacity, access is governed by prorating provisions, which may be set forth in the pipelines published tariffs. We believe we generally will have access to crude oil pipeline transportation services to the same extent as our similarly situated competitors.

Regulation of Sales and Transportation of Natural Gas

In 1989, the U.S. Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas. The FERC, which has the authority under the Natural Gas Act (NGA) to regulate prices, terms, and conditions for the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to FERC regulation, except interstate pipelines, to resell natural gas at market prices. However, either the U.S. Congress or the FERC (with respect to the resale of gas in interstate commerce) could re-impose price controls in the future. The U.S. Department of Energy (U.S. DOE) regulates the terms and conditions for the exportation and importation of natural gas (including liquefied natural gas or LNG). U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a Free Trade Agreement (FTA) with the United States that provides for national treatment of trade in natural gas; however, the U.S. DOE s regulation of imports and exports from and to countries without such FTAs is more comprehensive. The FERC also regulates the construction and operation of import and export facilities, including LNG terminals. Regulation of imports and exports and related facilities may materially affect natural gas markets and sales prices.

The FERC regulates interstate natural gas transportation rates and service conditions under the NGA and the Natural Gas Policy Act of 1978 (NGPA), which affects the marketing of natural gas we produce, as well as revenues we receive for sales of our natural gas. 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 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. The FERC has 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 services 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 provide any assurance that the pro-competitive regulatory approach established by the FERC will continue. However, we do not believe any action taken will affect us in a materially different way than other natural gas producers.

With regard to our physical sales of natural gas and derivative instruments relating to natural gas, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and the CFTC. See the discussion below of Other Federal Laws and Regulations Affecting Our Industry. Should we violate the anti-market manipulation laws and regulations, we could be subject to substantial penalties and related third-party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to various FERC orders, we may be required to submit reports to the FERC for some of our operations. See the discussion below of Other Federal Laws and Regulations Affecting Our Industry FERC Market Transparency and Reporting Rules.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policies on gathering systems have varied in the past, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting natural gas to point of sale locations. State regulation of natural gas gathering facilities generally includes various safety, environmental, and in some circumstances, equitable take requirements. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels in the future. We cannot predict what effect, if any, such changes may have on our operations, but the natural gas industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes, including changes in the interpretation of existing requirements or programs to implement those requirements. We do not believe we would be affected by any such regulatory changes in a materially different way than our similarly situated competitors.

Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas we produce, as well as the revenues we receive for sales of our natural gas. 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 the regulation of intrastate natural gas transportation in states in which we operate and ship natural gas on an intrastate basis will not affect our operations in a way that materially differs from the effect on the operations of our similarly situated competitors.

Regulation of Production

The production of crude oil and natural gas is subject to regulation under a wide range of federal, state and local statutes, rules, orders and regulations, which require, among other matters, 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, including provisions for the unitization or pooling of crude oil and natural gas properties, the establishment of maximum allowable rates of production from crude oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of crude oil and natural gas we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production, severance or excise tax with respect to the production and sale of crude 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 crude oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Other Federal Laws and Regulations Affecting Our Industry

Dodd-Frank Wall Street Reform and Consumer Protection Act. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) was enacted into law. This financial reform legislation includes provisions that require derivative transactions that are currently executed over-the-counter to be executed through an exchange and be centrally cleared. The Dodd-Frank Act requires the CFTC, the SEC, and other regulators to establish rules and regulations to implement the new legislation. The CFTC has issued final regulations to implement significant aspects of the legislation, including new rules for the registration of swap dealers and major swap participants (and related definitions of those terms), definitions of the term swap, rules to establish the ability to rely on the commercial end-user exception from the central clearing and exchange trading requirements, requirements for reporting and recordkeeping, rules on customer protection in the context of cleared swaps, and position limits for swaps and other transactions based on the price of certain reference contracts, some of which are referenced in our swap contracts. The position limits regulation has been vacated by a Federal court, and the CFTC is appealing that decision; accordingly, the effective date of these rules, if they are reinstated on appeal, or of replacement rules proposed and adopted by the CFTC, if applicable, is not currently known. Key regulations that have not yet been finalized include those establishing margin requirements for uncleared swaps, regulatory capital requirements for swap dealers and various trade execution requirements.

On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and certain index credit default swaps and setting compliance dates for different categories of market participants, the earliest of which is March 11, 2013. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. Although we expect to qualify for the end-user exception from the clearing requirement for our swaps, mandatory clearing requirements and revised capital requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for hedging.

The CFTC s swap regulations may require or cause our counterparties to collect margin from us, and if any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap execution facility. The ultimate effect of the proposed new rules and any additional regulations on our business is uncertain. Of particular concern is whether our status as a commercial end-user will allow our derivative counterparties to not require us to post margin in connection with our commodity price risk management activities. The remaining final rules and regulations on major provisions of the legislation, such as new margin requirements, will be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area, to the extent applicable to us or our derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial and commercial risks related to fluctuations in commodity prices. Additional effects of the new regulations, including increased regulatory reporting and recordkeeping costs, increased regulatory capital requirements for our counterparties, and market dislocations or disruptions, among other consequences, could have an adverse effect on our ability to hedge risks associated with our business.

Energy Policy Act of 2005. The Energy Policy Act of 2005 (EPAct 2005) included a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and made significant changes to the statutory framework affecting the energy industry. Among other matters, EPAct 2005 amended the NGA to add an anti-market manipulation provision making it unlawful for any entity, including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. In January 2006, the FERC issued rules implementing the anti-market manipulation provision of EPAct 2005. These anti-market manipulation rules apply to activities of natural gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements as described further below.

The EPAct 2005 also provided the FERC with additional civil penalty authority. The EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and NGPA. Under EPAct 2005, the FERC also has authority to order disgorgement of profits associated with any violation. The anti-market manipulation rules and enhanced civil penalty authority reflect an expansion of the FERC s enforcement authority.

FERC Market Transparency and Reporting Rules. The FERC requires wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers, and natural gas producers, to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. The FERC also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with the FERC s policy statement on price reporting. Failure to comply with these reporting requirements could subject us to enhanced civil penalty liability provided under EPAct 2005.

FTC and CFTC Market Manipulation Rules. Wholesale sales of petroleum are subject to provisions of the Energy Independence and Security Act of 2007 (EISA) and regulations by the FTC. Under the EISA, the FTC issued its Petroleum Market Manipulation Rule (the Rule), which became effective November 4, 2009, and prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. The Rule also bans intentional failures to state a material fact when the omission makes a statement misleading and distorts, or is likely to distort, market conditions for any product covered by the Rule. The FTC holds substantial enforcement authority under the EISA, including authority to request that a court impose fines of up to $1,000,000 per day per violation. Under the Commodity Exchange Act, the CFTC is directed to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to assess fines of up to $1,000,000 or triple the monetary gain for violations of its anti-market manipulation regulations.

Additional proposals and proceedings that may affect the crude oil and natural gas industry are pending before the U.S. Congress, the FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our crude oil and natural gas operations. We do not believe we will be affected by any such action materially different than similarly situated competitors.

Environmental, Health and Safety Regulation

General. Our operations are subject to stringent and complex federal, state, and local 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 crude 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 species of plants and animals; 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 crude oil and natural gas production below a rate otherwise possible. The regulatory burden on the crude oil and natural gas industry increases the cost of doing business and affects profitability. Additionally, the U.S. Congress and federal and state agencies frequently revise environmental, health and safety laws, rules and regulations, and any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the crude oil and natural gas industry could have a significant impact on our operating costs.

Environmental protection and natural gas flaring initiatives. Continental is committed to conducting its operations in a manner that protects the health, safety and welfare of the public, its employees and the environment. We strive to operate in accordance with all applicable regulatory requirements and have focused on continuously improving our health, safety, security and environmental (HSS&E) performance. We believe excellent HSS&E performance is critical to the long-term success of our business, and is a key component in maximizing return to shareholders. We also believe achieving this excellence requires the commitment and involvement of all employees in the Company, and we expect the same level of commitment from our contractors and vendors. Our commitment to HSS&E excellence is a paramount objective.

In connection with our HSS&E initiatives, we actively work to identify and manage the environmental risks and impact of our operations. Further, we set corporate objectives aimed at producing continuous improvement of our HSS&E efforts and we seek to provide the leadership and resources to enable our workforce to achieve our objectives. We routinely monitor our HSS&E performance to assess our conformity with environmental protection initiatives.

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We take a proactive and disciplined approach to emergency preparedness and business continuity planning to address the health, safety, security, and environmental risks inherent to our industry. We continually train our workforce and conduct drills to improve awareness and readiness to mitigate such risks. Further, emergency response plans are maintained that establish procedures to be utilized during any type of emergency affecting our personnel, facilities or the environment.

One current focus of our HSS&E initiatives is the reduction of air emissions produced from our operations, particularly with respect to flaring of natural gas from our operated well sites in the Bakken field of North Dakota, our most active area. The rapid growth of crude oil production in North Dakota in recent years, coupled with a lack of established natural gas transportation infrastructure in the state, has led to an industry-wide increase in flaring of natural gas produced in association with crude oil production. We recognize the environmental and financial risks associated with natural gas flaring and manage these risks on an ongoing basis. We set internal flaring reduction targets and to date have taken numerous actions to reduce flaring from our operated well sites. Our ultimate goal is to reduce natural gas flaring from our operated well sites to as close to zero percent flaring as possible. In operating areas such as the Buffalo Red River units in South Dakota, the quality of the natural gas is not adequate to meet requirements for sale, so we employ processes to efficiently combust the gas and minimize impacts to the environment.

In 2012, we made significant progress in achieving our flaring reduction goals. For example, in 2012 we set a goal to reduce the flaring of natural gas from our operated well sites in North Dakota Bakken by 50% by December 2012. During December 2012, the percentage of our natural gas production flared in North Dakota Bakken was approximately 10% compared to approximately 20% in December 2011. We believe this reduction is a notable accomplishment given the significant increase in our natural gas production in 2012, including areas with less developed infrastructure. Flaring from our operated well sites in North Dakota Bakken is significantly less than our industry peers operating in the play. According to data published by the North Dakota Industrial Commission, our industry as a whole was flaring approximately 33% of produced natural gas volumes in the state as of late 2012. Since we are one of the largest producers in the North Dakota Bakken field, we believe the percentage of natural gas flared by the industry as a whole would be higher than 33% if Continental s results were excluded from the NDIC s data.

We are experiencing similar or better flaring results in our other key operating areas outside of North Dakota. In Montana Bakken, we flared approximately 6% of the natural gas produced from our operated well sites in December 2012. Additionally, flared natural gas volumes from our operated SCOOP and Northwest Cana properties in Oklahoma are negligible given the existence of established natural gas transportation infrastructure in that state.

Through our HSS&E global initiatives, we will continue to work toward maintaining an industry-leading position with respect to flaring reduction efforts in North Dakota and our other key operating areas. In the Medicine Pole Hills units, we substantially reduced impacts from flaring by removing all gas engines that drive high pressure air injection and converting to electric engines. We expect to further reduce flared natural gas volumes as we continue to build out transportation infrastructure and transition to a greater use of ECO-Pad drilling in 2013 and beyond. Our flaring reduction progress is and will be dependent upon external factors such as investment from third parties in the development of gas gathering systems, state regulations, and the granting of reasonable right-of-way access by land owners, among other factors.

We have incurred in the past, and expect to incur in the future, capital and other expenditures related to environmental compliance. Such expenditures are included within our overall capital and operating budgets and are not separately itemized. Although we believe 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 materially impact our financial position or results of operations.

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Environmental, health and safety laws and regulations. Some of the existing environmental, health and safety laws and regulations we are subject to include, among others: (i) regulations by the Environmental Protection Agency (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 may require the removal of previously disposed wastes (including wastes disposed of or released by prior owners or operators), the cleanup of property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) federal Department of Transportation safety laws and comparable state and local requirements; (iv) the Clean Air Act and comparable state and local requirements, which establish pollution control requirements with respect to air emissions from our operations; (v) 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; (vi) 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 crude oil and other substances generated by our operations, into waters of the United States or state waters; (vii) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of solid and hazardous wastes, and comparable state statutes; (viii) the Safe Drinking Water Act and analogous state laws which impose requirements relating to our underground injection activities; (ix) the National Environmental Policy Act and comparable state statutes, which require government agencies, including the Department of Interior, to evaluate major agency actions that have the potential to significantly impact the environment; (x) the federal Occupational Safety and Health Act and comparable state statutes, which require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations, and (xi) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material.

Climate change. Federal, state and local laws and regulations are increasingly being enacted to address concerns about the effects the emission of carbon dioxide and other identified greenhouse gases may have on the environment and climate worldwide. These effects are widely referred to as climate change. Since its December 2009 endangerment finding regarding the emission of carbon dioxide, methane and other greenhouse gases, the EPA has begun regulating sources of greenhouse gas emissions under the federal Clean Air Act. Among several regulations requiring reporting or permitting for greenhouse gas sources, the EPA finalized its tailoring rule in May 2010 that identifies which stationary sources of greenhouse gases are required to obtain permits to construct, modify or operate on account of, and to implement the best available control technology for, their greenhouse gases. In November 2010, the EPA also finalized its greenhouse gas reporting requirements for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires annual reporting to the EPA of greenhouse gas emissions by such regulated facilities.

On April 17, 2012, the EPA issued final rules that established new air emission controls for crude oil and natural gas production and natural gas processing operations. These rules were published in the Federal Register on August 16, 2012. The EPA s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with crude oil and natural gas production and processing activities. The final rules require the use of reduced emission completions or green completions on all hydraulically-fractured wells completed or refractured after January 1, 2015 in order to achieve a 95 percent reduction in the emission of VOCs. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules may require modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Moreover, in recent years the U.S. Congress has considered establishing a cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Under past proposals, the EPA would issue or sell a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere.

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These allowances would be expected to escalate significantly in cost over time. The net effect of such legislation, if adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. In addition, while the prospect for such cap-and-trade legislation by the U.S. Congress remains uncertain, several states, including states in which we operate, have adopted, or are in the process of adopting, similar cap-and-trade programs.

As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop and produce crude oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the crude oil and natural gas we sell, emits carbon dioxide and other greenhouse gases. Thus, any current or future federal, state or local climate change initiatives could adversely affect demand for the crude oil and natural gas we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels, and therefore could have a material adverse effect on our business. Although our compliance with any greenhouse gas regulations may result in increased compliance and operating costs, we do not expect the compliance costs for currently applicable regulations to be material. Moreover, while it is not possible at this time to estimate the compliance costs or operational impacts for any new legislative or regulatory developments in this area, we do not anticipate being impacted to any greater degree than other similarly situated competitors.

Hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand and additives under pressure into rock formations to stimulate crude oil and natural gas production. Some activists have attempted to link hydraulic fracturing to various environmental problems, including adverse effects to drinking water supplies and migration of methane and other hydrocarbons. As a result, several federal agencies are studying the environmental risks with respect to hydraulic fracturing or evaluating whether to restrict its use. From time to time, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection, thereby requiring the crude oil and natural gas industry to obtain permits for hydraulic fracturing and to require disclosure of the additives used in the process. If adopted, such legislation could establish an additional level of regulation and permitting at the federal level. Scrutiny of hydraulic fracturing activities continues in other ways. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a number of federal agencies are analyzing environmental issues associated with hydraulic fracturing. The EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the draft results of which are anticipated to be available in 2014. Further, on May 11, 2012, the Bureau of Land Management (BLM) issued a proposed rule that would require public disclosure of chemicals used in hydraulic fracturing operations, and impose other operational requirements for all hydraulic fracturing operations on federal lands, including Native American trust lands. The Department of the Interior announced on January 18, 2013 that the BLM will issue a revised draft rule by March 31, 2013. In addition to these federal initiatives, several state and local governments, including states in which we operate, have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. We voluntarily participate in FracFocus, a national publicly accessible Internet-based registry developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. This registry, located at *www.fracfocus.org*, provides our industry with an avenue to voluntarily disclose additives used in the hydraulic fracturing process. We currently disclose the additives used in the hydraulic fracturing process on all wells we operate.

The adoption of any future federal, state or local laws, rules or implementing regulations imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations, increase our costs of compliance and doing business, and delay, prevent or prohibit the development of natural resources from unconventional formations. Compliance, or the consequences of our failure to comply, could have a material adverse effect on our financial condition and results of operations. At this time it is not possible to estimate the potential impact on our business if such federal or state legislation is enacted into law.

Employees

As of December 31, 2012, we employed 753 people. 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. We utilize the services of independent contractors to perform various field and other services.

Company Contact Information

Our corporate internet website is *www.clr.com.* Through the investor relations section of our website, we make available free of charge our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after the report is filed with or furnished to the SEC. For a current version of various corporate governance documents, including our Code of Ethics, please see our website. We intend to disclose amendments to, or waivers from, our Code of Ethics by posting to our website. Information contained on our website is not incorporated by reference into this report and you should not consider information contained on our website as part of this report.

We intend to use our website as a means of disclosing material information and for complying with our disclosure obligations under SEC Regulation FD. Such disclosures will be included on our website in the For Investors section. Accordingly, investors should monitor that portion of our website in addition to following our press releases, SEC filings and public conference calls and webcasts.

We file periodic reports and proxy statements with the 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 website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of the SEC s website is *www.sec.gov*.

Our principal executive offices are located at 20 N. Broadway, Oklahoma City, Oklahoma 73102, and our telephone number at that address is (405) 234-9000.

Item 1A. Risk Factors

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

We are subject to certain risks and hazards due to the nature of the business activities we conduct. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows, and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations.

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

The price we receive for our crude oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the

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markets for crude 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, but are not limited to, the following:

- worldwide and regional economic conditions impacting the global supply and demand for crude oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign crude oil and natural gas;
- political conditions in or affecting other crude oil-producing and natural gas-producing countries;
- the level of national and global crude oil and natural gas exploration and production;
- the level of national and global crude oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- changes in supply, demand, and refinery capacity for various grades of crude oil;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower crude oil and natural gas prices could reduce our cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; result in a decrease in the borrowing base under our revolving credit facility or otherwise limit our ability to borrow money or raise additional capital; and reduce the amount of crude oil and natural gas we can economically produce.

Substantial, extended decreases in crude oil and natural gas prices would render uneconomic a significant portion of our exploration, development and exploitation projects. This may result in significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in crude oil or natural gas prices would materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

A substantial portion of our producing properties are located in the North region, making us vulnerable to risks associated with having operations concentrated in this geographic area.

Because our operations are geographically concentrated in the North region (78% of our production in the fourth quarter of 2012 was from the North region), the success and profitability of our operations may be disproportionally exposed to the effect of regional events. These include, among others, fluctuations in the prices of crude oil and natural gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. In addition, our operations in the North region may be adversely affected by seasonal weather and lease stipulations designed to protect wildlife, which can intensify competition for the items described above during months when drilling is possible and may result in periodic shortages. The concentration of our operations in the North region also increases exposure to unexpected events that may occur in this region such as natural disasters or labor difficulties. Any one of these events has the potential to cause producing wells to be shut-in, delay operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition and results of operations.

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Volatility in the financial markets or in global economic factors could adversely impact our business and financial condition.

The economic recession experienced in 2008-2009 led to turmoil in U.S. and global economies that was characterized by extreme volatility and declines in prices of securities, diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of financial institutions, increased levels of unemployment, and an unprecedented level of intervention by the U.S. federal government and other governments. Improvements have occurred since 2008-2009 and some portions of the economy have stabilized and are showing signs of recovery. However, U.S. and global economies remain fragile and are still experiencing high unemployment, unstable consumer confidence and diminished consumer spending. Recent data has suggested the U.S. economy may be contracting again. Accordingly, although the economic recession experienced in recent years has ended, the extent and timing of the current recovery, and whether it can be sustained are uncertain. Economic weakness or uncertainty could reduce demand for crude oil and natural gas and put downward pressure on the prices of crude oil and natural gas. This would negatively impact our revenues, margins, profitability, operating cash flows, liquidity and financial condition. Such weakness or uncertainty could also cause our commodity hedging arrangements to become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Furthermore, our ability to collect receivables may be adversely impacted.

Historically, we have used cash flows from operations, borrowings under our revolving credit facility and capital market transactions to fund capital expenditures. Volatility in U.S. and global financial and equity markets, including market disruptions, limited liquidity, and interest rate volatility, may increase our cost of financing. We have an existing revolving credit facility with lender commitments totaling $1.5 billion and a borrowing base of $3.25 billion as of February 15, 2013. In the future, we may not be able to access adequate funding under our credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, which is solely at the discretion of our lenders, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations or increase their commitments to the borrowing base amount. Declines in commodity prices could result in a determination to lower our borrowing base in the future and, in such case, we could be required to repay indebtedness in excess of the borrowing base. Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required and on terms we find acceptable. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, complete new property acquisitions to replace reserves, take advantage of business opportunities, respond to competitive pressures, or refinance debt obligations as they come due.

Should any of the above risks occur, it could have a material adverse effect on our financial condition and results of operations.

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

The crude oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the exploration, development, exploitation, production and acquisition of crude oil and natural gas reserves. In 2012, we invested approximately $4.4 billion in our capital program, inclusive of property acquisitions. In October 2012, we announced a new five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017. Our capital expenditures for 2013 are budgeted to be $3.6 billion, excluding acquisitions which are not budgeted, with $3.3 billion allocated for drilling, capital workovers and facilities. To date, our capital expenditures have been financed with cash generated by operations, borrowings under our revolving credit facility and the issuance of debt and equity securities. The actual amount and timing of future capital expenditures may differ materially from our estimates as a result of, among others, commodity prices, available cash flows, unbudgeted acquisitions, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of transportation

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capacity, and regulatory, technological and competitive developments. Improvement in commodity prices may result in an increase in actual capital expenditures. Conversely, a significant decline in commodity prices could result in a decrease in actual capital expenditures. We intend to finance future capital expenditures primarily through cash flows from operations and 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 or the sale of assets. The issuance of additional debt requires a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital needs, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

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

- the amount of our proved reserves;
- the volume of crude oil and natural gas we are able to produce and sell from existing wells;
- the prices at which crude oil and natural gas are sold;
- our ability to acquire, locate and produce new reserves; and
- the ability and willingness of our banks to extend credit.

If revenues or the borrowing base under our revolving credit facility decrease as a result of lower crude 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 capital requirements, the failure to obtain additional financing could result in a curtailment of operations relating to development of our prospects, which in turn could lead to a decline in our crude oil and natural gas reserves and could adversely affect our business, financial condition and results of operations and our ability to achieve our growth plan.

Drilling for and producing crude 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 exploration, development and production activities. Our crude 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 crude 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. Our cost of drilling, completing and operating wells may be uncertain before drilling commences.

Risks we face while drilling include, but are not limited to, failing to place our well bore in the desired target producing zone; not staying in the desired drilling zone while drilling horizontally through the formation; failing to run our casing the entire length of the well bore; and not being able to run tools and other equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages; failing to run tools the entire length of the well bore during completion operations; and not successfully cleaning out the well bore after completion of the final fracture stimulation stage.

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

- abnormal pressure or irregularities in geological formations;

shortages of or delays in obtaining equipment and qualified personnel;

- mechanical difficulties, fires, explosions, ruptures of pipelines, equipment failures or accidents;
- adverse weather conditions and natural disasters, such as flooding, blizzards and ice storms;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- reductions in crude oil and natural gas prices;
- limited availability of financing with acceptable terms;
- title problems;
- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third party service providers;
- limitations in infrastructure, including transportation capacity or the market for crude oil and natural gas; and
- delays imposed by or resulting from compliance with regulatory requirements.

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 crude oil and natural gas reserves is complex. It requires interpretation of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracy in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See *Part I, Item 1. Business Crude Oil and Natural Gas Operations, Proved Reserves* for information about our estimated crude oil and natural gas reserves, PV-10, and Standardized Measure of discounted future net cash flows as of December 31, 2012.

In order to prepare estimates, we must project production rates and the amount 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, based on historical data but projected into the future, about matters such as crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude 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 crude oil and natural gas prices and other factors, many of which are beyond our control.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated crude oil and natural gas reserves.

You should not assume the present value of future net revenues from our proved reserves is the current market value of our estimated crude oil and natural gas reserves. In accordance with SEC rules, we base the estimated discounted future net revenues from proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months. Actual future net revenues from crude oil and natural gas properties will be affected by factors such as:

the actual cost and timing of development and production expenditures;

the amount and timing of actual production;

- the actual prices we receive for sales of crude oil and natural gas; and

- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of crude oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the crude oil and natural gas industry in general.

Actual future prices and costs may materially differ from those used in our estimate of the present value of future net revenues. If crude oil prices decline by $10.00 per barrel, our PV-10 as of December 31, 2012 would decrease approximately $2.1 billion. If natural gas prices decline by $1.00 per Mcf, our PV-10 as of December 31, 2012 would decrease approximately $819 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 crude 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 crude oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If enhanced recovery programs do not allow for the extraction of crude oil and natural gas in the manner or to the extent we anticipate, our future results of operations and financial condition could be materially adversely affected.

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

Accounting rules require that we periodically review the carrying values of our crude 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 values of our crude 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 crude oil and natural gas reserves, our reserves and production will decline, which could adversely affect our cash flows and results of operations.

Unless we conduct successful exploration, development and exploitation activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing crude oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude oil and natural gas reserves and production, and therefore our cash flows and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, 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 could be materially adversely affected.

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

- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants 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;
- personal injuries and death;
- natural disasters; and
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third party service providers.

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 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 we decide to drill may not yield crude oil or natural gas in economically producible quantities.

Prospects we decide to drill that do not yield crude oil or natural gas in economically producible quantities may adversely affect our results of operations and financial condition. In this report, we describe some of our current prospects and 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. It is not possible to predict with certainty in advance of drilling and testing whether any particular prospect will yield crude oil or natural gas in sufficient quantities to recover drilling or completion costs or be economically producible. 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 crude oil or natural gas will be present or, if present, whether crude oil or natural gas will be present in economically producible 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 crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals, available transportation capacity, and other factors. 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 crude 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. If we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 65% of our total net undeveloped acreage at December 31, 2012. At that date, we had leases representing 359,999 net acres expiring in 2013, 234,297 net acres expiring in 2014, and 279,486 net acres expiring in 2015. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our business depends on crude oil and natural gas transportation facilities, most of which are owned by third parties, and on the availability of rail transportation

The marketability of our crude oil and natural gas production depends in part on the availability, proximity and capacity of pipeline and rail systems owned by third parties. The lack or unavailability of capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of crude oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and rail systems, labor disputes and general economic conditions could adversely affect our ability to produce, gather, transport and sell crude oil and natural gas. As a result of pipeline constraints, the continuous increase in Williston Basin production, and our desire to transport our crude oil to coastal markets which currently provide the most favorable pricing, in December 2012 we transported approximately 72% of our operated crude oil production from the Bakken field by rail.

The disruption of third-party pipelines or rail transportation facilities due to labor disputes, maintenance and/or weather could negatively impact our ability to market and deliver our products and achieve the most favorable prices for our crude oil and natural gas production. We have no control over when or if access to such pipeline or rail facilities would be restored or what prices would be charged. A significant shut-in of production in connection with any of the aforementioned items could materially affect our cash flows, and if a substantial portion of the impacted production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

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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 developed and producing areas. 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 and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our crude oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. In order to conduct operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local 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 and local 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, crude 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 *Part I, Item 1. Business Regulation of the Crude Oil and Natural Gas Industry* for a description of the laws and regulations that affect us.

Strict or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. 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 are not able to recover the resulting costs through insurance or increased revenues, our business, financial condition and results of operations could be adversely affected.

Climate change legislation or regulations governing the emissions of greenhouse gases could result in increased operating costs and reduce demand for the crude oil, natural gas and natural gas liquids we produce.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the Earth s atmosphere and other climate changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of several regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act, such as the so-called tailoring rule adopted in May 2010, which imposes permitting and best available control technology requirements on the largest greenhouse gas stationary sources. In November 2010, the EPA also finalized its greenhouse gas reporting requirements for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires annual reporting to the EPA of greenhouse gas emissions by such regulated facilities.

On April 17, 2012, the EPA issued final rules that established new air emission controls for crude oil and natural gas production and natural gas processing operations. These rules were published in the Federal Register on

August 16, 2012. The EPA s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with crude oil and natural gas production and processing activities. The final rules require the use of reduced emission completions or green completions on all hydraulically-fractured wells completed or refractured after January 1, 2015 in order to achieve a 95 percent reduction in the emission of VOCs. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules may require modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of greenhouse gases, and almost half of the states, including states in which we operate, have enacted or passed measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition and results of operations.

Finally, it should be noted some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and inability to book future reserves.

A significant majority of our operations utilize hydraulic fracturing, an important and commonly used process in the completion of crude oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the high-pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production. Some activists have attempted to link hydraulic fracturing to various environmental problems, including adverse effects to drinking water supplies as well as migration of methane and other hydrocarbons. As a result, several federal agencies are studying potential environmental risks with respect to hydraulic fracturing or evaluating whether to restrict its use. From time to time legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection, thereby requiring the crude oil and natural gas industry to obtain permits for hydraulic fracturing, and to require disclosure of the additives used in the process. If ever adopted, such legislation could establish an additional level of regulation and permitting at the federal level. Scrutiny of hydraulic fracturing activities continues in other ways. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a number of federal agencies are analyzing environmental issues associated with hydraulic fracturing. The EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the draft results of which are anticipated to be available by 2014. Further, on May 11, 2012, the BLM issued a proposed rule that would require public disclosure of chemicals used in hydraulic fracturing operations, and impose other operational requirements for all hydraulic fracturing operations on federal lands, including Native American trust lands. The Department of the Interior announced on January 18, 2013 that BLM will issue a revised draft rule by March 31, 2013. At December 31, 2012, we held approximately 79,400 net undeveloped acres on federal land, representing approximately 6% of our total net undeveloped acres. In addition to these federal initiatives, several state and local governments, including states in which we operate, have moved to require disclosure of fracturing fluid components or to otherwise regulate their use more closely. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards.

The adoption of any future federal, state or local law or implementing regulation imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process, or the discovery of groundwater contamination or other adverse environmental effects directly connected to hydraulic fracturing, could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay, prevent or prohibit the development of natural resources from unconventional formations. In the event regulations are adopted that prohibit or significantly limit the use of hydraulic fracturing in states in which we operate, it would have a material adverse effect on our ability to economically find and develop crude oil and natural gas reserves in our strategic plays. The inability to achieve a satisfactory economic return could cause us to curtail or discontinue our exploration and development plans. Such a circumstance would have a material adverse effect on our business and would impair our ability to implement our growth plan.

Should we fail to comply with FERC, FTC and CFTC administered statutes and regulations on market behavior, we could be subject to substantial penalties and fines and other liabilities.

The FERC, under the EPAct 2005, and the FTC, under the Independence and Security Act of 2007, may impose or seek to impose through judicial action penalties for violations of anti-market manipulation rules for natural gas, crude oil and petroleum products of up to $1,000,000 per day for each violation. The CFTC, under the Commodity Exchange Act, has similar authority to impose penalties of up to $1,000,000 or triple the monetary gain for violation of anti-market manipulation rules for certain derivative contracts. In addition, while we have not been regulated by the FERC as a natural gas company under the NGA, the FERC has adopted regulations that may subject us to the FERC annual reporting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC, the FTC or CFTC from time to time. Failure to comply with any of these regulations in the future could subject us to civil penalty liability, as well as the disgorgement of profits and third-party claims.

Proposed legislation and regulation under consideration could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business.

Our operations are subject to extensive federal, state and local laws and regulations. Changes to existing laws or regulations, new laws or regulations, or changes in interpretations of laws and regulations may unfavorably impact us or the infrastructure used for transporting our products. Similarly, changes in regulatory policies and priorities could result in the imposition of new obligations upon us, such as increased reporting or audits. Any of these requirements could result in increased operating costs and could have a material adverse effect on our financial condition and results of operations. If such legislation, regulation or other requirements are adopted, they could result in, among other items, additional limitations and restrictions on hydraulic fracturing of wells, changes to the calculation of royalty payments, new safety requirements, and additional regulation of private energy commodity derivative and hedging activities. These and other potential laws, regulations and other requirements could increase our operating costs, reduce liquidity, delay operations or otherwise alter the way we conduct our business. This, in turn, could have a material adverse effect on our financial condition and results of operations.

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Certain federal income tax deductions currently available with respect to crude oil and natural gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in President Obama s fiscal year 2013 budget proposal are the elimination or deferral of certain key U.S. federal income tax deductions currently available to crude oil and natural gas exploration and production companies. Such proposed changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for crude oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. These proposed changes, if enacted, may negatively affect our financial condition and results of operations. The passage of legislation in response to President Obama s 2013 budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to crude oil and natural gas exploration and development, and any such change could negatively affect our cash flows available for capital expenditures and our ability to achieve our growth plan.

Regulations under the Dodd-Frank Act regarding derivatives could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risk and other risks associated with our business.

We use derivative instruments to manage our commodity price risk. In 2010, the U.S. Congress adopted the Dodd-Frank Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. This financial reform legislation includes provisions that require derivative transactions that are currently executed over-the-counter to be executed through an exchange and be centrally cleared. The new legislation was signed into law by President Obama on July 21, 2010 and requires the CFTC, the SEC, and in some cases banking regulators, to promulgate rules and regulations implementing the new legislation. The CFTC has issued final regulations to implement significant aspects of the legislation, including new rules for the registration of swap dealers and major swap participants (and related definitions of those terms), definitions of the term swap, rules to establish the ability to rely on the commercial end-user exception from the central clearing and exchange trading requirements, requirements for reporting and recordkeeping, rules on customer protection in the context of cleared swaps, and position limits for swaps and other transactions based on the price of certain reference contracts, some of which are referenced in our swap contracts. Key regulations that have not yet been finalized include those establishing margin requirements for uncleared swaps, regulatory capital requirements for swap dealers and various trade execution requirements.

On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and certain index credit default swaps and setting compliance dates for different categories of market participants, the earliest of which is March 11, 2013. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. If we do not qualify for the end-user exception from the clearing requirement for our swaps, the mandatory clearing requirements and revised capital requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for hedging. Some of the counterparties to our derivative instruments may also need or choose to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as our current counterparty.

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, lead to fewer potential counterparties, impose new recordkeeping and documentation requirements, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some

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legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial position and results of operations.

Competition in the crude oil and natural gas industry is intense, making it more difficult for us to acquire properties, market crude 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 crude oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Certain of our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for productive crude 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 in recent 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 financial condition and results of operations.

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

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As of December 31, 2012, non-operated properties represented 18% of our estimated proved developed reserves, 13% of our estimated proved undeveloped reserves, and 15% of our estimated total proved reserves. We have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures required to fund such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and materially adversely affect our financial condition and results of operations.

Our revolving credit facility and the indentures for our senior notes contain certain covenants and restrictions 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 revolving credit facility and the indentures for our senior notes include certain covenants and restrictions that, among others, 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 revolving credit facility and certain permitted liens;

- mergers, consolidations and sales of all or a 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; and
- the sale of assets.

The indentures for our outstanding senior notes limit our ability and the ability of our restricted subsidiaries to:

- incur, assume or guarantee additional indebtedness or issue redeemable stock;
- pay dividends on stock, repurchase stock or redeem subordinated debt;
- make certain investments;
- enter into certain transactions with affiliates;
- create certain liens on our assets;
- sell or otherwise dispose of certain assets, including capital stock of subsidiaries;
- restrict dividends, loans or other asset transfers from our restricted subsidiaries;
- enter into new lines of business; and
- consolidate with or merge with or into, or sell all or substantially all of our properties to another person.

Our revolving credit facility also requires us to maintain certain financial ratios, such as leverage ratios.

The restrictive covenants in our revolving credit facility and the senior note indentures may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our revolving credit facility or senior note indentures 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 revolving credit facility or senior note indentures, in which case, depending on the actions taken by the lenders or trustees thereunder or their successors or assignees, such lenders or trustees could elect to declare all amounts outstanding thereunder, together with accrued interest, to be due and payable. If we are unable to repay such borrowings or interest, our lenders could proceed against their collateral. If our indebtedness is accelerated, our assets may not be sufficient to repay in full such indebtedness.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit ratings. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flows used for drilling and place us at a competitive disadvantage. For example, as of February 15, 2013, outstanding borrowings under our revolving credit facility were $840 million and the impact of a 1% increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $8.4 million and a $5.2 million decrease in our annual net income. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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

Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($480.3 million in receivables at December 31, 2012), our joint interest receivables ($356.8 million at December 31, 2012), and counterparty credit risk

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associated with our derivative instrument receivables ($50.6 million at December 31, 2012). Joint interest receivables arise from billing entities who own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our crude oil and natural gas receivables with several significant customers. The largest purchaser of our crude oil and natural gas during the year ended December 31, 2012 accounted for approximately 21% of our total crude oil and natural gas revenues. We generally do not require our counterparties to provide collateral to support crude oil and natural gas sales receivables owed to us. Additionally, our use of derivative instruments involves the risk that our counterparties will be unable to meet their obligations under the arrangements. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition and results of operations.

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of crude oil and natural gas, we enter into derivative instruments for a portion of our crude oil and/or natural gas production, including collars and fixed price swaps. See *Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Crude Oil and Natural Gas Hedging* and *Part II, Item 8. Notes to Consolidated Financial Statements Note 5. Derivative Instruments* for a summary of our crude oil and natural gas commodity derivative positions. We do not designate any of our derivative instruments as hedges for accounting purposes and we record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative instruments expose us to the risk of financial loss in certain circumstances, including when:

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

In addition, our derivative arrangements limit the benefit we would receive from increases in the prices for crude oil and natural gas. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our undeveloped crude oil and natural gas reserves. As part of our risk management program, we have hedged a significant portion of our forecasted production. We utilize a combination of derivative contracts based on West Texas Intermediate (WTI) crude oil pricing, Inter-Continental Exchange (ICE) pricing for Brent crude oil, and Henry Hub pricing for natural gas. We believe our derivative contracts provide relevant protection from price fluctuations in the U.S. markets where we deliver and sell our production. The pricing for Brent crude oil is believed to be a better reflection of the sales prices realized in certain U.S. market centers. However, in the event Brent prices increase significantly, the prices realized in those U.S. market centers may no longer be reflective of Brent prices. In such a circumstance, we may incur significant realized cash losses upon settling our crude oil derivative instruments. Such losses may be incurred without seeing a corresponding increase in revenues from higher realized prices on our physical sales of crude oil.

Our Chairman and Chief Executive Officer owns approximately 68% of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our Company.

As of December 31, 2012, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owned 126,296,891 shares of our outstanding common stock representing approximately 68% of our outstanding common shares. As a result, Mr. Hamm is our controlling shareholder and will continue to be able to 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.

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 crude oil and natural gas prices and their differentials;
- future development costs, operating costs and property taxes; 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 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 prior to acquisition. 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 of the subject properties 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.

We may be subject to risks as a result of cyber attacks targeting systems and infrastructure used by the oil and gas industry.

Computers control nearly all of the crude oil and natural gas production and distribution systems in the U.S. and abroad, some of which are utilized to transport our production to market. A cyber attack directed at crude oil and natural gas production and distribution systems could damage critical distribution and/or storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. The occurrence of such an attack against any of the aforementioned production and distribution systems could have a material adverse effect on our financial condition and results of operations.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2012.

Item 2. Properties

The information required by Item 2 is contained in *Part I, Item 1. Business Crude Oil and Natural Gas Operations*.

Item 3. Legal Proceedings

In November 2010, an alleged class action was filed against the Company alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners as categorized in the petition from crude oil and natural gas wells located in Oklahoma. The plaintiffs have alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the alleged class. The Company has responded to the petition, denied the allegations and raised a number of affirmative defenses. Discovery is ongoing and information and documents continue to be exchanged. The Company is not currently able to estimate a reasonably possible loss or range of loss or what impact, if any, the action will have on its financial condition, results of operations or cash flows due to the preliminary status of the matter, the complexity and number of legal and factual issues presented by the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter. The class has not been certified. Plaintiffs have indicated that if the class is certified they may seek damages in excess of $145 million, a majority of which would be comprised of interest. The Company disputes plaintiffs claims, disputes that the case meets the requirements for a class action and is vigorously defending the case.

The Company is involved in various other legal proceedings such as commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims and similar matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material adverse effect on its financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

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Part II

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

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 for each quarter of the previous two years. No cash dividends were declared during the previous two years.

	2012 Quarter Ended				2011 Quarter Ended			
	March 31	June 30	September 30	December 31	March 31	June 30	September 30	December 31
High	$ 97.19	$ 91.82	$ 84.19	$ 80.59	$ 73.48	$ 72.73	$ 71.77	$ 72.98
Low	67.94	61.50	61.02	66.07	56.55	57.89	46.25	42.43
Cash Dividend								

Our senior notes restrict the payment of dividends under certain circumstances and we do not anticipate paying any cash dividends on our common stock in the foreseeable future. As of February 20, 2013, the number of record holders of our common stock was 157. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 49,600. On February 20, 2013, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was $82.43 per share.

The following table summarizes our purchases of our common stock during the quarter ended December 31, 2012:

Period	Total number of shares purchased (1)	Average price paid per share (2)	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 program (3)
October 1, 2012 to October 31, 2012	41,404	$ 75.67		
November 1, 2012 to November 30, 2012	27,384	$ 70.57		
December 1, 2012 to December 31, 2012	6,141	$ 73.14		
Total	74,929	$ 73.60		

(1) In connection with restricted stock grants under the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan), we adopted a policy that enables employees to surrender shares to cover their tax liability. All shares purchased above represent shares surrendered to cover tax liabilities. We paid the associated taxes to the Internal Revenue Service.

(2) The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares.

(3) We are unable to determine at this time the total amount of securities or approximate dollar value of those securities that could potentially be surrendered to us pursuant to our policy that enables employees to surrender shares to cover their tax liability associated with the vesting of restrictions on shares under the 2005 Plan.

Equity Compensation Plan Information

The following table sets forth the information as of December 31, 2012 relating to equity compensation plans:

	Number of Shares to be Issued Upon Exercise of	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity Compensation Plans (1)

	Outstanding Options		
Equity Compensation Plans Approved by Shareholders		$	1,867,967
Equity Compensation Plans Not Approved by Shareholders			

(1) All remaining shares (1,867,967) are available for issuance under the 2005 Plan.

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Performance Graph

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on our common stock with the cumulative total returns of the Standard & Poor s 500 Index (S&P 500 Index), the Dow Jones US Oil and Gas Index (Dow Jones US O&G Index), and a peer group of companies.

In years prior to 2012, the total shareholder return of our common stock was compared to the total returns of the S&P 500 Index and a group of peer companies. Companies included in our peer group represented publicly traded crude oil and natural gas exploration and production companies similar in size and operations to us. In recent years, companies deemed to be peers have been acquired or have merged with other companies in our industry. Additionally, the rapid growth of our Company in recent years has outpaced the growth of our peers. These factors have caused fluctuations in the companies comprising our peer group from one year to the next. To mitigate the impact of these fluctuations and provide more consistency to the performance graph disclosure year after year, in 2012 we elected to replace our peer group with the Dow Jones US O&G Index for disclosure purposes. In this year of transition, we have presented the total returns of both the peer group and Dow Jones US O&G Index in the performance graph below.

The peer group, which represents the group presented in the performance graph from our 2011 Form 10-K, is comprised of Cabot Oil & Gas Corporation, Cimarex Energy Co., Concho Resources Inc., Denbury Resources Inc., Forest Oil Corporation, Newfield Exploration Company, Pioneer Natural Resources Company, Range Resources Corporation, Ultra Petroleum Corp., and Whiting Petroleum Corporation.

The information provided in this section is being furnished to, and not filed with, the SEC. As such, this information is neither subject to Regulation 14A or 14C nor to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended. As required by those rules, the performance graph was prepared based upon the following assumptions:

- $100 was invested in our common stock, the S&P 500 Index, the Dow Jones US O&G Index, and the peer group on December 31, 2007 at the closing price on such date;

- investment in the 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.

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Item 6. Selected Financial Data

This section presents our selected consolidated financial data for the years ended December 31, 2008 through 2012. The selected financial data presented below is not intended to replace our consolidated financial statements.

The following consolidated financial data, as it relates to each of the fiscal years ended December 31, 2008 through 2012, has been derived from our audited consolidated financial statements for such periods. You should read the following selected consolidated financial data in connection with *Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements and related notes included elsewhere in this report. The selected consolidated results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Income Statement data					
(in thousands, except per share data)					
Crude oil and natural gas sales	$ 2,379,433	$ 1,647,419	$ 948,524	$ 610,698	$ 939,906
Gain (loss) on derivative instruments, net (1)	154,016	(30,049)	(130,762)	(1,520)	(7,966)
Total revenues	2,572,520	1,649,789	839,065	626,211	960,490
Income from continuing operations	739,385	429,072	168,255	71,338	320,950
Net income	739,385	429,072	168,255	71,338	320,950
Basic earnings per share:					
From continuing operations	$ 4.08	$ 2.42	$ 1.00	$ 0.42	$ 1.91
Net income per share	$ 4.08	$ 2.42	$ 1.00	$ 0.42	$ 1.91
Shares used in basic earnings per share	181,340	177,590	168,985	168,559	168,087
Diluted earnings per share:					
From continuing operations	$ 4.07	$ 2.41	$ 0.99	$ 0.42	$ 1.89
Net income per share	$ 4.07	$ 2.41	$ 0.99	$ 0.42	$ 1.89
Shares used in diluted earnings per share	181,846	178,230	169,779	169,529	169,392
Production					
Crude oil (MBbl) (2)	25,070	16,469	11,820	10,022	9,147
Natural gas (MMcf)	63,875	36,671	23,943	21,606	17,151
Crude oil equivalents (MBoe)	35,716	22,581	15,811	13,623	12,006
Average sales prices (3)					
Crude oil ($/Bbl)	$ 84.59	$ 88.51	$ 70.69	$ 54.44	$ 88.87
Natural gas ($/Mcf)	4.20	5.24	4.49	3.22	6.90
Crude oil equivalents ($/Boe)	66.83	73.05	59.70	45.10	77.66
Average costs per Boe ($/Boe) (3)					
Production expenses	$ 5.49	$ 6.13	$ 5.87	$ 6.89	$ 8.40
Production taxes and other expenses	6.42	6.42	4.82	3.37	4.84
Depreciation, depletion, amortization and accretion	19.44	17.33	15.33	15.34	12.30
General and administrative expenses (4)	3.42	3.23	3.09	3.03	2.95
Proved reserves at December 31					
Crude oil (MBbl)	561,163	326,133	224,784	173,280	106,239
Natural gas (MMcf)	1,341,084	1,093,832	839,568	504,080	318,138
Crude oil equivalents (MBoe)	784,677	508,438	364,712	257,293	159,262
Other financial data (in thousands)					
Net cash provided by operating activities	$ 1,632,065	$ 1,067,915	$ 653,167	$ 372,986	$ 719,915
Net cash used in investing activities	(3,903,370)	(2,004,714)	(1,039,416)	(499,822)	(927,617)
Net cash provided by financing activities	2,253,490	982,427	379,943	135,829	204,170
EBITDAX (5)	1,963,123	1,303,959	810,877	450,648	757,708
Total capital expenditures	4,358,572	2,224,096	1,237,189	433,991	988,593
Balance Sheet data at December 31 (in thousands)					
Total assets	$ 9,140,009	$ 5,646,086	$ 3,591,785	$ 2,314,927	$ 2,215,879
Long-term debt, including current maturities	3,539,721	1,254,301	925,991	523,524	376,400
Shareholders equity	3,163,699	2,308,126	1,208,155	1,030,279	948,708

(1) Derivative instruments are not designated as hedges for accounting purposes and, therefore, realized and unrealized changes in fair value of the instruments are shown separately from crude oil and natural gas sales. The amounts above include unrealized non-cash mark-to-market gains (losses) on derivative instruments of $199.7 million, $4.1 million, ($166.2) million and ($2.1) million for the years ended December 31, 2012, 2011, 2010, and 2009, respectively. There were no unrealized gains or losses on derivative instruments for the year ended December 31, 2008.

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(2) At various times, we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. For the year 2012, crude oil sales volumes were 112 MBbls less than crude oil production volumes. For the year 2011, crude oil sales volumes were 30 MBbls less than crude oil production volumes. For the year 2010, crude oil sales volumes were 78 MBbls more than crude oil production volumes. For the year 2009, crude oil sales volumes were 82 MBbls less than crude oil production volumes. For the year 2008, crude oil sales volumes were 97 MBbls more than crude oil production volumes.

(3) Average sales prices and average costs per Boe have been computed using sales volumes and exclude any effect of derivative transactions.

(4) General and administrative expenses ($/Boe) include non-cash equity compensation expenses of $0.82 per Boe, $0.73 per Boe, $0.74 per Boe, $0.84 per Boe and $0.75 per Boe for the years ended December 31, 2012, 2011, 2010, 2009 and 2008, respectively. Additionally, general and administrative expenses include corporate relocation expenses of $0.22 per Boe and $0.14 per Boe for the years ended December 31, 2012 and 2011. No corporate relocation expenses were incurred prior to 2011.

(5) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by generally accepted accounting principles. Reconciliations of net income and operating cash flows to EBITDAX are provided in *Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures.*

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes, as well as the selected consolidated financial data included elsewhere in this report. Our operating results for the periods discussed below may not be indicative of future performance. For additional discussion of crude oil and natural gas reserve information, please see *Part I, Item 1. Business Crude Oil and Natural Gas Operations.* The following discussion and analysis includes forward-looking statements and should be read in conjunction with *Part I, Item 1A. Risk Factors* in this report, along with *Cautionary Statement for the Purpose of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995* at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are an independent crude oil and natural gas exploration and production company with properties in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, and the Red River units. The South region includes Kansas and all properties south of Kansas and west of the Mississippi River including the South Central Oklahoma Oil Province (SCOOP), Northwest Cana, and Arkoma Woodford plays in Oklahoma. The SCOOP and Northwest Cana plays were previously combined by us and referred to as the Anadarko Woodford play. In December 2012, we sold the producing crude oil and natural gas properties in our East region. Our remaining East region properties are comprised of undeveloped leasehold acreage east of the Mississippi River that will be managed as part of our exploration program.

We focus our exploration activities in large new or developing crude oil and liquids-rich 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 crude oil and natural gas reserves from unconventional formations. In October 2012, we announced a new five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017.

We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas. We expect growth in our revenues and operating income will primarily depend on commodity prices and our ability to increase our crude oil and natural gas production. In recent months and years, there has been significant volatility in crude oil and natural gas prices due to a variety of factors we cannot control or predict, including political and economic events, weather conditions, and competition from other energy sources. These factors impact supply and demand for crude oil and natural gas, which affect crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by price differences in the markets where we deliver our production.

2012 Highlights

Proved reserves

At December 31, 2012, our estimated proved reserves totaled 784.7 MMBoe, an increase of 54% over proved reserves of 508.4 MMBoe at December 31, 2011. Extensions and discoveries resulting from our exploration and development activities were the primary drivers of our proved reserves growth in 2012, adding 233.7 MMBoe of proved reserves during the year, with strategic acquisitions adding 82.0 MMBoe. Our extensions and discoveries were primarily driven by successful drilling results and strong production growth in the Bakken field. Our proved reserves in the Bakken field totaled 563.6 MMBoe at December 31, 2012, representing a 92% increase from 294.2 MMBoe at year-end 2011.

Our properties in the Bakken field comprised 72% of our proved reserves at December 31, 2012, with the SCOOP and Northwest Cana plays in Oklahoma comprising 14% and the Red River units in North Dakota, South Dakota and Montana comprising 10%. Estimated proved developed producing reserves were 309.0 MMBoe at

December 31, 2012, representing 39% of our total estimated proved reserves compared with 40% at year-end 2011.

Crude oil reserves comprised 72%, or 561.2 MMBoe, of our estimated proved reserves at December 31, 2012 compared to 64% at December 31, 2011. The increased percentage of crude oil reserves at December 31, 2012 is a reflection of our continued strategy of focusing on the exploration for and development of high-value crude oil and liquids-rich plays.

We seek to operate wells in which we own an interest. At December 31, 2012, we operated wells that accounted for 85% of our total proved reserves and 84% of our PV-10. By controlling operations, we are able to more effectively manage the costs and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used. Additionally, our business strategy has historically focused on reserve and production growth through exploration and development activities. For the three-year period ended December 31, 2012, we added 490.9 MMBoe of proved reserves through extensions and discoveries, compared to 84.4 MMBoe added through acquisitions.

Production, revenues and operating cash flows

For the year ended December 31, 2012, our crude oil and natural gas production totaled 35,716 MBoe (97,583 Boe per day), representing a 58% increase from production of 22,581 MBoe (61,865 Boe per day) for the year ended December 31, 2011. Crude oil represented 70% of our 2012 production compared to 73% for 2011. The decreased percentage of crude oil production resulted from our natural gas production growth in 2012 of 74% outpacing our crude oil production growth of 52% due in part to the connecting of new and existing wells in North Dakota to gas processing plants, thereby resulting in a higher percentage of our production coming from natural gas in 2012.

Our crude oil and natural gas production totaled 9,829 MBoe (106,831 Boe per day) for the fourth quarter of 2012, a 4% increase over production of 9,472 MBoe (102,964 Boe per day) for the third quarter of 2012 and a 42% increase over production of 6,920 MBoe (75,219 Boe per day) for the fourth quarter of 2011. Crude oil represented 72% of our production for the fourth quarter of 2012, 70% for the third quarter of 2012, and 72% for the fourth quarter of 2011.

The increase in 2012 production was primarily driven by higher production from our properties in the North Dakota Bakken field and the Northwest Cana and SCOOP plays in Oklahoma due to the continued success of our drilling programs in those areas. Our Bakken production in North Dakota increased to 18,679 MBoe for the year ended December 31, 2012, a 92% increase over the comparable 2011 period. Fourth quarter 2012 production in North Dakota Bakken totaled 5,430 MBoe, a 6% increase over the third quarter of 2012 and 66% higher than the fourth quarter of 2011. Production in the Northwest Cana play totaled 4,097 MBoe for the year ended December 31, 2012, 134% higher than the same period in 2011. Northwest Cana production increased 22% in the fourth quarter of 2012 compared to the fourth quarter of 2011, yet decreased 15% from the third quarter of 2012 due to reduced drilling activity. Production from our properties in the emerging SCOOP play in south-central Oklahoma totaled 1,654 MBoe for the year ended December 31, 2012, a 297% increase over the comparable 2011 period. SCOOP production totaled 655 MBoe for the 2012 fourth quarter, a 39% increase over the third quarter of 2012 and a 281% increase over the fourth quarter of 2011.

Our crude oil and natural gas revenues for the year ended December 31, 2012 increased 44% to $2.4 billion due to a 58% increase in sales volumes partially offset by a 9% decrease in realized commodity prices compared to the same period in 2011. Our realized price per Boe decreased $6.22 to $66.83 for the year ended December 31, 2012 compared to 2011 due to lower commodity prices and higher crude oil differentials realized. Crude oil represented 89% of our total 2012 crude oil and natural gas revenues compared to 88% for 2011.

Crude oil and natural gas revenues totaled $670.4 million for the fourth quarter of 2012, a 32% increase over revenues of $508.3 million for the 2011 fourth quarter due to a 39% increase in sales volumes partially offset by a 5% decrease in realized commodity prices. Crude oil represented 88% of our total crude oil and natural gas revenues for the fourth quarter of 2012 compared to 89% for the 2011 fourth quarter.

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Our cash flows from operating activities for the year ended December 31, 2012 were $1.6 billion, a 53% increase from $1.1 billion provided by our operating activities during the comparable 2011 period. For the fourth quarter of 2012, operating cash flows totaled $484.2 million, 22% higher than operating cash flows of $398.1 million for the 2011 fourth quarter. The increased operating cash flows were primarily due to higher crude oil and natural gas revenues driven mainly by increased sales volumes, partially offset by lower realized sales prices, an increase in realized losses on derivatives and higher production expenses, production taxes, general and administrative expenses and other expenses associated with the growth of our operations over the past year.

Capital expenditures and property acquisitions

For the year ended December 31, 2012, we invested approximately $4.4 billion in our capital program (including $15.0 million of seismic costs and $49.0 million of capital costs associated with increased accruals for capital expenditures), focusing primarily on increased exploration and development in the Bakken field of North Dakota and Montana and the SCOOP play in south-central Oklahoma. Our 2012 capital expenditures include $1.3 billion of unbudgeted property acquisitions, most notably from the acquisitions described below.

In December 2012, we acquired certain producing and undeveloped properties in the Bakken play of North Dakota from a third party for $663.3 million. In the transaction, we acquired interests in approximately 119,000 net acres as well as producing properties with production of approximately 6,500 net Boe per day.

In August 2012, we acquired the crude oil and natural gas properties of Wheatland Oil Inc. in the states of Mississippi, Montana, North Dakota and Oklahoma through the issuance of approximately 3.9 million shares of our common stock. The fair value of the common stock transferred at closing was approximately $279 million. As a result of the transaction, we acquired an increased interest in approximately 37,900 net acres as well as producing properties primarily in the Bakken play, which added production of approximately 3,200 net Boe per day.

In February 2012, we acquired certain producing and undeveloped properties in the Bakken play of North Dakota from a third party for $276 million. In the transaction, we acquired interests in approximately 23,100 net acres as well as producing properties with production of approximately 1,000 net Boe per day.

Through leasing and acquisitions in 2012, we increased our Bakken acreage by 24% from 915,863 net acres at year-end 2011 to 1,139,803 net acres at year-end 2012.

Our capital expenditures budget for 2013 is $3.6 billion, excluding acquisitions. Our 2013 capital program is expected to continue focusing on exploratory and development drilling in the Bakken field and SCOOP play. We expect to continue participating as a buyer of properties if and when we have the ability to increase our position in strategic plays at favorable terms.

We hedge a portion of our anticipated future production to achieve more predictable cash flows and reduce our exposure to fluctuations in commodity prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. We expect our cash flows from operations, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to meet our budgeted capital expenditure needs for the next 12 months; however, we may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms.

Property dispositions

In 2012, we completed the following dispositions of non-strategic properties in an effort to redeploy capital to our strategic areas that we believe will deliver higher future growth potential. We may continue to seek opportunities to sell non-strategic properties if and when we have the ability to dispose of such assets at favorable terms.

In December 2012, we sold the producing properties in our East region to a third party for $126.4 million and recognized a pre-tax gain on the transaction of $68.0 million. The disposed properties

comprised 399 MBoe, or 1%, of our total crude oil and natural gas production for 2012. Crude oil and natural gas revenues for the disposed properties amounted to $34.6 million for 2012, representing 1% of our total crude oil and natural gas revenues for the year. The disposed properties had represented approximately 1% of our total proved reserves prior to disposition.

In June 2012, we sold certain non-strategic leaseholds and producing properties in Oklahoma to a third party for $15.9 million and recognized a pre-tax gain on the transaction of $15.9 million. The disposed properties represented an immaterial portion of our total proved reserves and production.

In February 2012, we sold certain non-strategic leaseholds and producing properties in Wyoming to a third party for $84.4 million and recognized a pre-tax gain on the transaction of $50.1 million. The disposed properties had represented 3.2 MMBoe, or 1%, of our total proved reserves at December 31, 2011 and 259 MBoe, or 1%, of our 2011 total crude oil and natural gas production.

Corporate relocation

The previously announced relocation of our corporate headquarters from Enid, Oklahoma to Oklahoma City was completed during 2012. For the year ended December 31, 2012, we recognized $7.8 million of costs associated with our relocation efforts, of which $0.5 million was recognized during the fourth quarter. Cumulative relocation costs recognized in 2011 and 2012 totaled $11.0 million.

Financial and operating highlights

We use a variety of financial and operating measures to evaluate our operations and assess our performance. Among these measures are:

- Volumes of crude oil and natural gas produced,
- Crude oil and natural gas prices realized,
- Per unit operating and administrative costs, and
- EBITDAX (a non-GAAP financial measure)

The following table contains financial and operating highlights for the periods presented.

	Year ended December 31,		
	2012	2011	2010
Average daily production:			
Crude oil (Bbl per day)	68,497	45,121	32,385
Natural gas (Mcf per day)	174,521	100,469	65,598
Crude oil equivalents (Boe per day)	97,583	61,865	43,318
Average sales prices: (1)			
Crude oil ($/Bbl)	$ 84.59	$ 88.51	$ 70.69
Natural gas ($/Mcf)	4.20	5.24	4.49
Crude oil equivalents ($/Boe)	66.83	73.05	59.70
Production expenses ($/Boe) (1)	5.49	6.13	5.87
General and administrative expenses ($/Boe) (1)	3.42	3.23	3.09
Net income (in thousands)	739,385	429,072	168,255
Diluted net income per share	4.07	2.41	0.99

EBITDAX (in thousands) (2)	1,963,123	1,303,959	810,877

(1) Average sales prices and per unit expenses have been calculated using sales volumes and exclude any effect of derivative transactions.

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(2) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided subsequently under the heading *Non-GAAP Financial Measures*.

Results of Operations

The following table presents selected financial and operating information for each of the periods presented.

	Year Ended December 31,		
	2012	2011	2010
	In thousands, except sales price data		
Crude oil and natural gas sales	$ 2,379,433	$ 1,647,419	$ 948,524
Gain (loss) on derivative instruments, net (1)	154,016	(30,049)	(130,762)
Crude oil and natural gas service operations	39,071	32,419	21,303
Total revenues	2,572,520	1,649,789	839,065
Operating costs and expenses (2)	1,279,713	889,037	528,744
Other expenses, net	137,611	73,307	51,854
Income before income taxes	1,155,196	687,445	258,467
Provision for income taxes	415,811	258,373	90,212
Net income	$ 739,385	$ 429,072	$ 168,255
Production volumes:			
Crude oil (MBbl) (3)	25,070	16,469	11,820
Natural gas (MMcf)	63,875	36,671	23,943
Crude oil equivalents (MBoe)	35,716	22,581	15,811
Sales volumes:			
Crude oil (MBbl) (3)	24,958	16,439	11,898
Natural gas (MMcf)	63,875	36,671	23,943
Crude oil equivalents (MBoe)	35,604	22,551	15,889
Average sales prices: (4)			
Crude oil ($/Bbl)	$ 84.59	$ 88.51	$ 70.69
Natural gas ($/Mcf)	4.20	5.24	4.49
Crude oil equivalents ($/Boe)	66.83	73.05	59.70

(1) Amounts include unrealized non-cash mark-to-market gains on derivative instruments of $199.7 million and $4.1 million for the years ended December 31, 2012 and 2011, respectively, and an unrealized non-cash mark-to-market loss on derivative instruments of $166.2 million for the year ended December 31, 2010.

(2) Amounts are net of gains on sales of assets of $136.0 million, $20.8 million, and $29.6 million for the years ended December 31, 2012, 2011, and 2010, respectively. See *Notes to Consolidated Financial Statements Note 13. Property Acquisitions and Dispositions* for further discussion of the transactions.

(3) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between produced and sold crude oil volumes. Crude oil sales volumes were 112 MBbls less than crude oil production for the year ended December 31, 2012, 30 MBbls less than crude oil production for the year ended December 31, 2011 and 78 MBbls more than crude oil production for the year ended December 31, 2010.

(4) Average sales prices have been calculated using sales volumes and exclude any effect of derivative transactions.

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Year ended December 31, 2012 compared to the year ended December 31, 2011

Production

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

	Year Ended December 31, 2012		2011			Volume
	Volume	Percent	Volume	Percent	Volume increase	percent increase
Crude oil (MBbl)	25,070	70%	16,469	73%	8,601	52%
Natural Gas (MMcf)	63,875	30%	36,671	27%	27,204	74%
Total (MBoe)	35,716	100%	22,581	100%	13,135	58%

	Year Ended December 31, 2012		2011		Volume	Percent
	MBoe	Percent	MBoe	Percent	increase (decrease)	increase (decrease)
North Region	27,207	76%	17,462	77%	9,745	56%
South Region	8,110	23%	4,705	21%	3,405	72%
East Region (1)	399	1%	414	2%	(15)	(4%)
Total	35,716	100%	22,581	100%	13,135	58%

(1) In December 2012, we sold the producing crude oil and natural gas properties in our East region to a third party for $126.4 million, subject to customary post-closing adjustments. See *Notes to Consolidated Financial Statements Note 13. Property Acquisitions and Dispositions* for further discussion of the transaction.

Crude oil production volumes increased 52% during the year ended December 31, 2012 compared to the year ended December 31, 2011. Production increases in the Bakken field, the Northwest Cana play and SCOOP play contributed incremental production volumes in 2012 of 8,493 MBbls, an 81% increase over production in these areas for the same period in 2011. Production growth in these areas is primarily due to increased drilling and completion activity resulting from our drilling program. Additionally, production in the Red River units increased 177 MBbls, or 4%, in 2012 due to new wells being completed and enhanced recovery techniques being successfully applied.

Natural gas production volumes increased 27,204 MMcf, or 74%, during the year ended December 31, 2012 compared to the same period in 2011. Natural gas production in the Bakken field increased 9,414 MMcf, or 104%, for the year ended December 31, 2012 compared to the same period in 2011 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in the play. Natural gas production in the Northwest Cana and SCOOP plays in Oklahoma increased 17,839 MMcf, or 156%, due to additional wells being completed and producing in the year ended December 31, 2012 compared to the same period in 2011. Further, natural gas production increased 716 MMcf, or 81%, in non-Bakken areas in the North region compared to 2011 due to the completion of new wells during the period. These increases were partially offset by a decrease in production volumes of 837 MMcf, or 6%, from non-core areas in our South region due to a combination of natural declines in production and reduced drilling activity prompted by the pricing environment for natural gas in those areas.

Revenues

Our total revenues consist of sales of crude oil and natural gas, realized and unrealized changes in the fair value of our derivative instruments and revenues associated with crude oil and natural gas service operations.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the year ended December 31, 2012 were $2.38 billion, a 44% increase from sales of $1.65 billion for the same period in 2011. Our sales volumes increased 13,053 MBoe, or 58%, over 2011 due to the success of our drilling programs in the North Dakota Bakken field and Northwest Cana play, along with early success being achieved in the emerging SCOOP play in

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Oklahoma. Our realized price per Boe decreased $6.22 to $66.83 for the year ended December 31, 2012 from $73.05 for the year ended December 31, 2011 due to lower commodity prices and higher crude oil differentials realized.

The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the year ended December 31, 2012 was $9.06 compared to $6.39 for the year ended December 31, 2011. Overall increased production and constrained logistical factors had a negative effect on our realized crude oil prices during 2012 and resulted in higher differentials compared to 2011. Factors contributing to the changing differential included a continued increase in crude oil production across the Williston Basin from the Bakken play as well as increased production and imports from Canada. Additionally, pipeline transportation capacity remained constrained in the Williston Basin throughout 2012 and it was not until the latter part of the year that improved rail transportation takeaway capacity began to have a positive effect on differentials. Positive effects of stronger sales pricing in coastal U.S. markets began to be realized in the fourth quarter of the year despite high costs being incurred for rail transportation. As a result, our crude oil differentials to NYMEX improved late in the year and averaged $3.21 per barrel for the fourth quarter.

Derivatives. We have entered into a number of derivative instruments, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and drilling program. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value in the consolidated statements of income under the caption Gain (loss) on derivative instruments, net , which is a component of total revenues.

Changes in commodity futures price strips during 2012 had an overall positive net impact on the fair value of our derivatives, which resulted in net positive revenue adjustments of $154.0 million for the year. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices. The following table presents the impact on total revenues related to realized and unrealized gains and losses on derivative instruments for the periods presented.

	Year ended December 31,	
	2012	2011
	In thousands	
Realized gain (loss) on derivatives:		
Crude oil derivatives	$ (55,579)	$ (71,411)
Natural gas derivatives	9,858	37,305
Total realized gain (loss) on derivatives	$ (45,721)	$ (34,106)
Unrealized gain (loss) on derivatives		
Crude oil derivatives	$ 202,478	$ 18,753
Natural gas derivatives	(2,741)	(14,696)
Total unrealized gain (loss) on derivatives	$ 199,737	$ 4,057
Gain (loss) on derivative instruments, net	$ 154,016	$ (30,049)

Crude Oil and Natural Gas Service Operations. Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

	Year Ended December 31,		Increase
Reclaimed crude oil sales	2012	2011	(Decrease)
Average sales price ($/Bbl)	$ 91.64	$ 92.30	$ (0.66)
Sales volumes (MBbls)	272	259	13

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The increase in sales volumes reflected above, partially offset by lower realized sales prices, resulted in a $1.3 million net increase in reclaimed oil revenues to $25.1 million for the year ended December 31, 2012. Additionally, revenues from saltwater disposal and other services increased $5.4 million to $14.0 million resulting from increased activity. Associated crude oil and natural gas service operations expenses increased $5.5 million to $32.2 million for the year ended December 31, 2012 due mainly to an increase in the costs of purchasing and treating reclaimed crude oil for resale and in providing saltwater disposal services.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 41% to $195.4 million for the year ended December 31, 2012 from $138.2 million for the year ended December 31, 2011. This increase is primarily the result of higher production volumes from an increase in the number of producing wells. Production expense per Boe decreased to $5.49 for the year ended December 31, 2012 compared to $6.13 per Boe for the year ended December 31, 2011. This decrease was due in part to higher costs being incurred in the prior year resulting from the abnormal rainfall and flooding in North Dakota during the 2011 second quarter. The increased 2011 costs, coupled with reduced production from curtailed and shut-in wells in North Dakota during that time, resulted in higher per-unit production expenses in 2011 compared to 2012.

Production taxes and other expenses increased $83.6 million, or 58%, to $228.4 million for the year ended December 31, 2012 compared to the year ended December 31, 2011 as a result of higher crude oil and natural gas revenues resulting primarily from increased sales volumes. Production taxes and other expenses in the consolidated statements of income include other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $29.9 million and $13.7 million for the years ended December 31, 2012 and 2011, respectively. The increase in other charges is primarily due to the significant increase in natural gas sales volumes in the current year. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 8.2% for the year ended December 31, 2012 compared to 7.9% for the year ended December 31, 2011. The increase is due to higher taxable revenues coming from North Dakota, our most active area, which has production tax rates of up to 11.5% of crude oil revenues. Production taxes are generally based on the wellhead value 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 crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana and Oklahoma, new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rate. Our overall production tax rate is expected to further increase as we continue to expand our operations in North Dakota and as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

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

	Year Ended December 31,	
$/Boe	2012	2011
Production expenses	$ 5.49	$ 6.13
Production taxes and other expenses	6.42	6.42
Production expenses, production taxes and other expenses	$ 11.91	$ 12.55

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Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. The following table shows the components of exploration expenses for the periods indicated.

	Year Ended December 31,	
(in thousands)	2012	2011
Exploratory geological and geophysical costs	$ 22,740	$ 19,971
Dry hole costs	767	7,949
Exploration expenses	$ 23,507	$ 27,920

Exploratory geological and geophysical costs increased $2.8 million for the year ended December 31, 2012 due to an increase in acquisitions of seismic data in connection with our increased capital budget for 2012. No significant dry holes were drilled during 2012. Dry hole costs recognized in 2011 were primarily concentrated in Arkoma Woodford and Michigan.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $301.2 million, or 77%, for the year ended December 31, 2012 compared to the year ended December 31, 2011 primarily due to a 58% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Year Ended December 31,	
$/Boe	2012	2011
Crude oil and natural gas production	$ 19.10	$ 16.90
Other equipment	0.25	0.29
Asset retirement obligation accretion	0.09	0.14
Depreciation, depletion, amortization and accretion	$ 19.44	$ 17.33

The increase in DD&A per Boe is partially the result of a gradual shift in our production base from our historic base of the Red River units in the Cedar Hills field to newer production bases in the Bakken and Oklahoma Woodford plays. The producing properties in our newer areas typically carry higher DD&A rates due to the higher cost of developing reserves in those areas compared to our older, more mature properties.

Property Impairments. Property impairments increased in the year ended December 31, 2012 by $13.8 million to $122.3 million compared to $108.5 million for the year ended December 31, 2011.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually insignificant non-producing properties are amortized on an aggregate basis based on our estimated experience of successful drilling and the average holding period. Impairments of non-producing properties increased $25.5 million for the year ended December 31, 2012 to $117.9 million compared to $92.4 million for the year ended December 31, 2011. The increase resulted from a larger base of amortizable costs in the current year coupled with changes in management s estimates of the undeveloped properties no longer expected to be developed before lease expiration. Given current and projected low prices for natural gas, we have elected to defer drilling on certain dry gas properties, thereby resulting in higher amortization of costs in the current year. We currently have no individually significant non-producing properties that are assessed for impairment on a property-by-property basis.

Impairment provisions for proved properties were $4.3 million for the year ended December 31, 2012 compared to $16.1 million for the same period in 2011. We evaluate proved crude oil and natural gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then we impair it based on an estimate of fair value based on discounted cash flows. Impairments of proved properties in 2012 primarily reflect uneconomic operating results in a non-Woodford single-well field in our South region. Impairment provisions for proved properties in 2011 reflect uneconomic operating results for initial wells drilled on our acreage in the Niobrara play in Colorado.

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General and Administrative Expenses. General and administrative (G&A) expenses increased $48.9 million to $121.7 million for the year ended December 31, 2012 from $72.8 million for the comparable period in 2011. G&A expenses include non-cash charges for equity compensation of $29.1 million and $16.6 million for the years ended December 31, 2012 and 2011, respectively. The increase in equity compensation in 2012 resulted from larger grants of restricted stock due to employee growth and new executive management personnel along with an increase in our grant-date stock prices, which resulted in increased expense recognition in 2012 compared to the prior year. G&A expenses excluding equity compensation increased $36.4 million for the year ended December 31, 2012 compared to the same period in 2011. The increase was due in part to an increase in personnel costs and office-related expenses associated with our rapid growth. Over the past year, our Company has grown from having 609 total employees in December 2011 to 753 total employees in December 2012, a 24% increase. Additionally, in March 2011 we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. Our relocation was completed during 2012. For the year ended December 31, 2012, we recognized approximately $7.8 million of costs in G&A expenses associated with the relocation compared to $3.2 million in 2011. Cumulative relocation costs recognized through December 31, 2012 totaled approximately $11.0 million.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

	Year Ended December 31,	
$/Boe	2012	2011
General and administrative expenses	$ 2.38	$ 2.36
Non-cash equity compensation	0.82	0.73
Corporate relocation expenses	0.22	0.14
Total general and administrative expenses	$ 3.42	$ 3.23

Interest Expense. Interest expense increased $64.0 million to $140.7 million for the year ended December 31, 2012 from $76.7 million for the comparable period in 2011 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the year ended December 31, 2012 was approximately $2.3 billion with a weighted average interest rate of 5.6% compared to a weighted average outstanding long-term debt balance of approximately $970.0 million and a weighted average interest rate of 7.2% for the comparable period in 2011. The increase in outstanding debt resulted from borrowings incurred to fund increased amounts of capital expenditures and property acquisitions in 2012 compared to 2011. On March 8, 2012 and August 16, 2012, we issued $800 million and $1.2 billion, respectively, of 5% Senior Notes due 2022 and used the net proceeds from those issuances to repay credit facility borrowings, to fund a portion of our 2012 capital budget and for general corporate purposes.

Our weighted average outstanding credit facility balance increased to $322.1 million for the year ended December 31, 2012 compared to $70.0 million for the year ended December 31, 2011. The weighted average interest rate on our credit facility borrowings was 2.3% for the year ended December 31, 2012 compared to 2.4% for the same period in 2011. At December 31, 2012, we had $595 million of outstanding borrowings on our credit facility compared to $358.0 million outstanding at December 31, 2011. The increase in credit facility borrowings in 2012 was driven by the aforementioned increase in capital expenditures and property acquisitions during the year.

Income Taxes. We recorded income tax expense for the year ended December 31, 2012 of $415.8 million compared to $258.4 million for the year ended December 31, 2011. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences. See *Notes to Consolidated Financial Statements Note 8. Income Taxes* for more information.

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Year ended December 31, 2011 compared to the year ended December 31, 2010

Production

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

	Year Ended December 31, 2011		2010			
	Volume	Percent	Volume	Percent	Volume increase	Percent increase
Crude oil (MBbl)	16,469	73%	11,820	75%	4,649	39%
Natural Gas (MMcf)	36,671	27%	23,943	25%	12,728	53%
Total (MBoe)	22,581	100%	15,811	100%	6,770	43%

	Year Ended December 31, 2011		2010			
	MBoe	Percent	MBoe	Percent	Volume increase (decrease)	Percent increase (decrease)
North Region	17,462	77%	12,431	79%	5,031	40%
South Region	4,705	21%	2,915	18%	1,790	61%
East Region	414	2%	465	3%	(51)	(11%)
Total	22,581	100%	15,811	100%	6,770	43%

Crude oil production volumes increased 39% during the year ended December 31, 2011 compared to the year ended December 31, 2010. Production increases in the Bakken field and the SCOOP and Northwest Cana plays in the Oklahoma Woodford formation contributed incremental production volumes in 2011 of 4,410 MBbls, a 72% increase over production in these areas for the same period in 2010. Production growth in these areas was primarily due to increased drilling activity and higher well completions resulting from our accelerated drilling program for 2011. Additionally, production in the Cedar Hills field increased 203 MBbls, or 5%, in 2011 due to new wells being completed and enhanced recovery techniques being successfully applied.

Natural gas production volumes increased 12,728 MMcf, or 53%, during the year ended December 31, 2011 compared to the same period in 2010. Natural gas production in the North Dakota Bakken field was up 3,529 MMcf, or 88%, for the year ended December 31, 2011 compared to the same period in 2010 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in North Dakota. Natural gas production in the SCOOP and Northwest Cana plays increased 8,971 MMcf, or 366%, due to additional wells being completed and producing in the year ended December 31, 2011 compared to the same period in 2010. Further, natural gas production increased 502 MMcf in non-Woodford areas of our South region due to the completion of new wells during the period. These increases were partially offset by a 498 MMcf decrease in natural gas production from our Arkoma Woodford properties, which consist primarily of dry gas. In 2011, we scaled back our Arkoma Woodford drilling program due to the pricing environment for natural gas.

Revenues

Our total revenues are comprised of sales of crude oil and natural gas, realized and unrealized changes in the fair value of our derivative instruments and revenues associated with crude oil and natural gas service operations.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the year ended December 31, 2011 were $1,647.4 million, a 74% increase from sales of $948.5 million for the same period in 2010. Our sales volumes increased 6,662 MBoe, or 42%, over the same period in 2010 due to the success of our drilling programs in the North Dakota Bakken field and the SCOOP and Northwest Cana plays. Our realized price per Boe increased $13.35 to $73.05 for the year ended December 31, 2011 from $59.70 for the year ended December 31, 2010. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the year ended December 31, 2011 was $6.39 compared to $9.02 for the year ended December 31, 2010. In

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2011, a significant portion of our operated crude oil production in the North region was sold in markets other than Cushing, Oklahoma and was priced, apart from transportation costs, at a premium to West Texas Intermediate benchmark pricing, which resulted in improved differentials.

Derivatives. Changes in commodity futures price strips during 2011 had an overall negative net impact on the fair value of our derivatives, which resulted in net negative revenue adjustments of $30.0 million for the year. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices. The following table presents the impact on total revenues related to realized and unrealized gains and losses on derivative instruments for the periods presented.

	Year ended December 31, 2011	2010
	In thousands	
Realized gain (loss) on derivatives:		
Crude oil derivatives	$ (71,411)	$ 13,195
Natural gas derivatives	37,305	22,300
Total realized gain (loss) on derivatives	$ (34,106)	$ 35,495
Unrealized gain (loss) on derivatives		
Crude oil derivatives	$ 18,753	$ (186,013)
Natural gas derivatives	(14,696)	19,756
Total unrealized gain (loss) on derivatives	$ 4,057	$ (166,257)
Gain (loss) on derivative instruments, net	$ (30,049)	$ (130,762)

Crude Oil and Natural Gas Service Operations. Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

Reclaimed crude oil sales	Year Ended December 31, 2011	2010	Variance
Average sales price ($/Bbl)	$ 92.30	$ 69.35	$ 22.95
Sales volumes (MBbls)	259	227	32

The average sales price for reclaimed crude oil sold from our central treating units was $22.95 per barrel higher for the year ended December 31, 2011 than the comparable 2010 period. This contributed to an increase in reclaimed crude oil revenues of $7.0 million to $23.8 million and contributed to an overall increase in crude oil and natural gas service operations revenue of $11.1 million for the year ended December 31, 2011. Also contributing to the increase in crude oil and natural gas service operations revenue was a $3.3 million increase in saltwater disposal income resulting from increased activity. Associated crude oil and natural gas service operations expenses increased $8.6 million to $26.7 million during the year ended December 31, 2011 from $18.1 million during the year ended December 31, 2010 due mainly to an increase in the costs of purchasing and treating reclaimed crude oil for resale and in providing saltwater disposal services.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 48% to $138.2 million for the year ended December 31, 2011 from $93.2 million for the year ended December 31, 2010. This increase was primarily the result of higher production volumes from an increase in the number of producing wells. Production expenses per Boe increased to $6.13 for the year ended December 31, 2011 from $5.87 per Boe for the year ended December 31, 2010. Contributing to the per-unit increase were increases in well site and road maintenance costs and saltwater disposal costs in the 2011 second quarter, all resulting from abnormal rainfall

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and flooding in North Dakota in April and May 2011. Also contributing to the per-unit increase were higher workover expenditures from increased activity as well as general inflationary pressure on the costs of oilfield services and equipment.

Production taxes and other expenses increased $68.2 million, or 89%, to $144.8 million during the year ended December 31, 2011 compared to the year ended December 31, 2010 as a result of higher crude oil and natural gas revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses include charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $13.7 million and $6.1 million for the year ended December 31, 2011 and 2010, respectively. The increase in other charges is primarily due to the significant increase in natural gas sales volumes in 2011. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 7.9% for the year ended December 31, 2011 compared to 7.5% for the year ended December 31, 2010. The increase was due to the expiration of various tax incentives coupled with higher taxable revenues in North Dakota, our most active area, which has production tax rates of up to 11.5% of crude oil revenues. Our overall production tax rate is expected to further increase as we continue to expand our operations in North Dakota and as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

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

	Year Ended December 31,	
$/Boe	2011	2010
Production expenses	$ 6.13	$ 5.87
Production taxes and other expenses	6.42	4.82
Production expenses, production taxes and other expenses	$ 12.55	$ 10.69

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. The following table shows the components of exploration expenses for the periods indicated.

	Year Ended December 31,	
(in thousands)	2011	2010
Exploratory geological and geophysical costs	$ 19,971	$ 9,739
Dry hole costs	7,949	3,024
Exploration expenses	$ 27,920	$ 12,763

Exploratory geological and geophysical costs increased $10.2 million for the year ended December 31, 2011 due to an increase in acquisitions of seismic data in connection with our increased capital budget for 2011. Dry hole costs increased $4.9 million in 2011 resulting from increased drilling activity. Dry hole costs in 2011 were mainly concentrated in Arkoma Woodford and Michigan.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $147.3 million, or 60%, in the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to a 43% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Year Ended December 31,	
$/Boe	2011	2010
Crude oil and natural gas production	$ 16.90	$ 14.92
Other equipment	0.29	0.24
Asset retirement obligation accretion	0.14	0.17
Depreciation, depletion, amortization and accretion	$ 17.33	$ 15.33

The increase in DD&A per Boe was partially the result of a gradual shift in our production from our historic base of the Red River units in the Cedar Hills field to newer production bases in the Bakken and Oklahoma Woodford plays. The producing properties in our newer areas typically carry higher DD&A rates due to the higher cost of developing reserves in those areas compared to our older, more mature properties.

Property Impairments. Property impairments increased in the year ended December 31, 2011 by $43.5 million to $108.5 million compared to $65.0 million for the year ended December 31, 2010.

Impairments of non-producing properties increased $29.1 million for the year ended December 31, 2011 to $92.4 million compared to $63.3 million for the year ended December 31, 2010. The increase resulted from a larger base of amortizable costs in 2011 coupled with changes in management s estimates of the undeveloped properties no longer expected to be developed before lease expiration. Given the pricing environment for natural gas, we elected to defer drilling on certain dry gas properties, thereby resulting in higher amortization of costs in 2011. In 2011, we had no individually significant non-producing properties that were assessed for impairment on a property-by-property basis.

Impairment provisions for proved crude oil and natural gas properties were $16.1 million for the year ended December 31, 2011 compared to $1.7 million for the same period in 2010. Impairments of proved properties in 2011 primarily reflect uneconomic operating results for initial wells drilled on our acreage in the Niobrara play in Colorado. Impairments in 2010 reflect uneconomic operating results in the East region and a non-Bakken Montana field in the North region.

General and Administrative Expenses. General and administrative (G&A) expenses increased $23.7 million to $72.8 million for the year ended December 31, 2011 from $49.1 million for the comparable period in 2010. G&A expenses include non-cash charges for equity compensation of $16.6 million and $11.7 million for the years ended December 31, 2011 and 2010, respectively. The increase in equity compensation in 2011 resulted from larger grants of restricted stock due to employee growth along with an increase in our grant-date stock prices during the year which increased expense recognition. G&A expenses excluding equity compensation increased $18.8 million for the year ended December 31, 2011 compared to the same period in 2010. The increase was primarily related to an increase in personnel costs and office-related expenses associated with our rapid growth. In 2011, we grew from 493 total employees in December 2010 to 609 total employees in December 2011, a 24% increase. In March 2011, we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. For the year ended December 31, 2011, we recognized approximately $3.2 million of costs in G&A expenses associated with the relocation.

The following table shows the components of G&A expenses on a unit of sales basis.

	Year Ended December 31,	
$/Boe	2011	2010
General and administrative expenses	$ 2.36	$ 2.35
Non-cash equity compensation	0.73	0.74
Corporate relocation expenses	0.14	
Total general and administrative expenses	$ 3.23	$ 3.09

Interest Expense. Interest expense increased $23.6 million, or 44%, for the year ended December 31, 2011 compared to the same period in 2010 due to increases in our weighted average outstanding long-term debt balance and our weighted average interest rate. Our weighted average interest rate for the year ended December 31, 2011 was 7.2% with a weighted average outstanding long-term debt balance of $970.0 million compared to a weighted average interest rate of 7.0% with a weighted average outstanding long-term debt balance of $685.8 million for the same period in 2010. We issued $200 million of 7 3/8% Senior Notes in April 2010 and $400 million of 7 1/8% Senior Notes in September 2010, the net proceeds of which were used to repay credit facility borrowings that carried lower interest rates.

Our weighted average outstanding credit facility balance decreased to $70.0 million for the year ended December 31, 2011 compared to $121.7 million for the year ended December 31, 2010. The weighted average interest rate on our credit facility borrowings was 2.4% for the year ended December 31, 2011 compared to 2.7% for the same period in 2010. At December 31, 2011, we had $358.0 million of outstanding borrowings on our credit facility at a weighted average interest rate of 2.0%.

Income Taxes. We recorded income tax expense for the year ended December 31, 2011 of $258.4 million compared to $90.2 million for the year ended December 31, 2010. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences. See *Notes to Consolidated Financial Statements Note 8. Income Taxes* for more information.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our credit facility and the issuance of debt and equity securities. Our 58% increase in sales volumes for the year ended December 31, 2012 compared to the same period in 2011 resulted in improved cash flows from operations. Our liquidity has improved as we have more borrowing availability on our credit facility resulting from increases made in 2012 to our credit facility s borrowing base and aggregate commitments as discussed below under the heading *Revolving Credit Facility*.

At December 31, 2012, we had $35.7 million of cash and cash equivalents and $900.2 million of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities was $1.6 billion and $1.1 billion for the years ended December 31, 2012 and 2011, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues driven by higher sales volumes, partially offset by lower realized sales prices, an increase in realized losses on derivatives and increases in production expenses, production taxes, general and administrative expenses, and other expenses associated with the growth of our operations during the year.

Cash flows used in investing activities

During the years ended December 31, 2012 and 2011, we had cash flows used in investing activities (excluding asset sales) of $4.1 billion and $2.0 billion, respectively, related to our capital program, inclusive of dry hole costs. The increase in cash flows used in investing activities in 2012 was primarily due to our larger capital budget and drilling program for 2012 coupled with an increase in property acquisitions in the current year. The use of cash for capital expenditures was partially offset by proceeds received from dispositions of non-strategic assets during the year. Proceeds from the sale of assets amounted to $214.7 million for 2012, primarily related to our February 2012 disposition of certain Wyoming properties for $84.4 million, our June 2012 disposition of certain Oklahoma properties for $15.9 million, and our December 2012 disposition of certain East region properties for $126.4 million, of which $14.0 million had not yet been received at December 31, 2012. Proceeds from the sale of assets amounted to $30.9 million for 2011, primarily related to our March 2011 disposition of certain Michigan properties for $22.0 million and our December 2011 disposition of certain North region properties for $8.0 million.

Cash flows from financing activities

Net cash provided by financing activities for the year ended December 31, 2012 was $2.3 billion primarily resulting from the receipt of $787.0 million of net proceeds from the March 2012 issuance of $800 million of 5% Senior Notes due 2022 and an additional $1.21 billion of net proceeds received from the issuance of $1.2 billion of additional 2022 Notes at 102.375% of par in August 2012, along with $237 million of net borrowings made on our credit facility during the year to fund a portion of our 2012 capital program. Net cash provided by financing activities of $982.4 million for the year ended December 31, 2011 was primarily the result of receiving $659.7 million of net proceeds from the issuance of an aggregate 10,080,000 shares of our common stock in March 2011 coupled with net borrowings of $328 million on our credit facility to fund a portion of our 2011 capital program.

Future Sources of Financing

Although we cannot provide any assurance, assuming continued strength in crude oil prices and successful implementation of our business strategy, we believe funds from operating cash flows, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, 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 for the next 12 months. We may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms.

Based on our planned production growth and derivative contracts we have in place to limit the downside risk of adverse price movements associated with the forecasted sale of future production, we currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. We intend to finance future capital expenditures primarily through cash flows from operations and through borrowings under our credit facility, but we may also issue debt or equity securities or sell assets. The issuance of additional debt requires a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Revolving Credit Facility

We have a credit facility which had aggregate lender commitments totaling $1.5 billion and a borrowing base of $3.25 billion at December 31, 2012, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in December 2012, whereby the lenders approved an increase in the borrowing base from $2.75 billion to $3.25 billion. In July 2012, our lender commitments were increased from the previous level of $1.25 billion to the current level of $1.5 billion. The aggregate commitment level may be further increased from time to time (provided no default exists) up to the lesser of $2.5 billion or the borrowing base then in effect. Borrowings under the credit facility bear interest at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by us, plus a margin ranging from 150 to 250 basis points, depending on the percentage of the borrowing base utilized, or the lead bank s reference rate (prime) plus a margin ranging from 50 to 150 basis points.

The commitments under our credit facility, which matures on July 1, 2015, are from a syndicate of 14 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. If one or more lenders cannot fund its commitment, we would not have the full availability of the $1.5 billion commitment.

We had $595.0 million of outstanding borrowings and $900.2 million of borrowing availability (after considering outstanding borrowings and letters of credit) on our credit facility at December 31, 2012. The outstanding borrowings at December 31, 2012 mainly represent borrowings incurred to fund a portion of our December 2012 acquisition of North Dakota Bakken properties for $663.3 million. At November 30, 2012, prior to the acquisition, we had no borrowings outstanding on our credit facility.

As of February 15, 2013, we had $840.0 million of outstanding borrowings and $655.2 million of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. The increase in outstanding borrowings subsequent to December 31, 2012 resulted from borrowings incurred to fund a portion of our 2013 capital program.

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Our 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. Our credit agreement also contains requirements that we maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 4.0 to 1.0. As defined by our credit agreement, the current ratio represents our ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit agreement and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided subsequently under the caption *Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with these covenants at December 31, 2012 and expect to maintain compliance for at least the next 12 months. At December 31, 2012, our current ratio, as defined, was 1.6 to 1.0 and our total funded debt to EBITDAX ratio was 1.8 to 1.0. We do not believe the restrictive covenants are reasonably likely to limit our ability to undertake additional debt or equity financing to a material extent.

In the future, we may not be able to access adequate funding under our credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations or increase their commitments to the borrowing base amount. We expect the next borrowing base redetermination to occur in the second quarter of 2013. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base.

If we are unable to access funding on acceptable terms when needed, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Derivative Activities

As part of our risk management program, we hedge a portion of our anticipated future crude oil and natural gas production to achieve more predictable cash flows and to reduce our exposure to fluctuations in crude oil and natural gas prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions and our desire to have the cash flows needed to fund the development of our inventory of undeveloped crude oil and natural gas reserves in conjunction with our growth strategy. Refer to *Note 5. Derivative Instruments* in *Notes to Consolidated Financial Statements* for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts at December 31, 2012 and the estimated fair value of those contracts as of that date. Additionally, a summary of derivative contracts entered into after December 31, 2012 is provided subsequently in this section of our Annual Report under the heading *Crude Oil and Natural Gas Hedging.*

Future Capital Requirements

Senior Note Maturities

On March 8, 2012, we issued $800 million of 5% Senior Notes due 2022 and received net proceeds of approximately $787.0 million after deducting the initial purchasers fees. The net proceeds were used to repay a portion of the borrowings then outstanding under our credit facility.

On August 16, 2012, we issued an additional $1.2 billion of 5% Senior Notes due 2022 (the New Notes). The New Notes were issued pursuant to the indenture applicable to the $800 million of 5% Senior Notes previously issued on March 8, 2012, resulting in a total of $2.0 billion aggregate principal amount of 5% Senior Notes due 2022 being issued under that indenture. The New Notes have substantially identical terms to the $800 million of Senior Notes originally issued in March 2012. The New Notes were sold at 102.375% of par value, resulting in net proceeds of approximately $1.21 billion after deducting the initial purchasers fees. We used a portion of the net proceeds from the offering to repay all amounts then outstanding under our credit facility and used the remaining net proceeds to fund a portion of our 2012 capital budget and for general corporate purposes.

The following table summarizes the maturity dates, semi-annual interest payment dates, and optional redemption periods related to our outstanding senior note obligations.

	2019 Notes	2020 Notes	2021 Notes	2022 Notes
Maturity date	October 1, 2019	October 1, 2020	April 1, 2021	September 15, 2022
Semi-annual interest payment dates	April 1, October 1	April 1, October 1	April 1, October 1	March 15, Sept 15
Decreasing call premium redemption period (1)	October 1, 2014	October 1, 2015	April 1, 2016	March 15, 2017
Make-whole redemption period (2)	October 1, 2014	October 1, 2015	April 1, 2016	March 15, 2017
Redemption using equity offering proceeds (3)		October 1, 2013	April 1, 2014	March 15, 2015

(1) On or after these dates, we have the option to redeem all or a portion of our senior notes at the decreasing redemption prices specified in the respective senior note indentures (together, the Indentures) plus any accrued and unpaid interest to the date of redemption.
(2) At any time prior to these dates, we have the option to redeem all or a portion of our senior notes at the make-whole redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption.
(3) At any time prior to these dates, we may redeem up to 35% of the principal amount of our senior notes under certain circumstances with the net cash proceeds from one or more equity offerings at the redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption. The optional redemption period for the 2019 Notes using equity offering proceeds expired on October 1, 2012.

Currently, we have no plans or intentions of exercising an early redemption option on the senior notes. Our senior notes are not subject to any mandatory redemption or sinking fund requirements.

The Indentures contain certain restrictions on our ability to incur additional debt, pay dividends on common stock, make certain investments, create certain liens on assets, engage in certain transactions with affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. We were in compliance with these covenants as of December 31, 2012 and expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants will materially limit our ability to undertake additional debt or equity financing. Two of our subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have no independent assets or operations, fully and unconditionally guarantee the senior notes. Our other subsidiary, 20 Broadway Associates LLC, the value of whose assets and operations are minor, does not guarantee the senior notes.

Capital Expenditures

We evaluate opportunities to purchase or sell crude oil and natural gas properties and expect to 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. Acquisition expenditures are not budgeted.

For the year ended December 31, 2012, we invested approximately $4.4 billion in our capital program (including $15.0 million of seismic costs and $49.0 million of capital costs associated with increased accruals for capital expenditures). Our 2012 capital expenditures include $1.3 billion of unbudgeted property acquisitions, most

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notably from the (i) February 2012 acquisition of properties in the Bakken play of North Dakota for $276 million, of which $51.7 million was allocated to producing properties, (ii) the non-cash acquisition of properties from Wheatland Oil Inc. in August 2012 recorded at $177 million, of which $167.4 million was allocated to producing properties, and (iii) the December 2012 acquisition of properties in the Bakken play of North Dakota for $663.3 million, of which $477.1 million was allocated to producing properties.

Our 2012 capital expenditures were allocated as follows:

	Amount *in millions*
Exploration and development drilling	$ 2,752
Land costs	164
Capital facilities, workovers and re-completions	55
Buildings, vehicles, computers and other equipment	53
Seismic	15
Capital expenditures, excluding acquisitions	$ 3,039
Acquisitions of producing properties	571
Acquisitions of non-producing properties	572
Non-cash acquisition of Wheatland oil and gas properties	177
Total acquisitions	$ 1,320
Total capital expenditures	$ 4,359

Our 2012 capital program focused primarily on increased development in the North Dakota Bakken field and the SCOOP play in south-central Oklahoma.

In October 2012, we announced a new five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017. For 2013, our capital expenditures budget is $3.6 billion excluding acquisitions, which is expected to be allocated as follows:

	Amount *in millions*
Exploration and development drilling	$ 3,155
Land costs	220
Capital facilities, workovers and re-completions	175
Buildings, vehicles, computers and other equipment	30
Seismic	20
Total 2013 capital budget, excluding acquisitions	$ 3,600

Our 2013 capital plan is expected to continue focusing on increased exploratory and development drilling in the Bakken field and SCOOP play. We expect to participate as a buyer of properties when and if we have the ability to increase our position in our strategic plays at favorable terms.

Although we cannot provide any assurance, assuming continued strength in crude oil prices and successful implementation of our business strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe funds from operating cash flows, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to fund our planned 2013 capital budget; however, we may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, available cash flows, unbudgeted acquisitions, actual drilling results, the availability of drilling rigs and other services and equipment, changes in commodity prices, and regulatory, technological and competitive developments.

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Contractual Obligations

The following table presents our contractual obligations and commitments as of December 31, 2012:

		Payments due by period			
(in thousands)	Total	Less than 1 year (2013)	Years 2 and 3 (2014-2015)	Years 4 and 5 (2016-2017)	More than 5 years
Arising from arrangements on the balance sheet:					
Credit facility borrowings	$ 595,000	$	$ 595,000	$	$
Senior Notes (1)	2,900,000				2,900,000
Note payable (2)	20,421	1,950	4,091	4,358	10,022
Interest expense (3)	1,516,769	178,856	352,390	337,245	648,278
Asset retirement obligations (4)	47,171	2,227	6,418	1,539	36,987
Arising from arrangements not on balance sheet:					
Operating leases (5)	4,266	1,965	1,914	196	191
Drilling rig commitments (6)	94,574	79,852	14,722		
Fracturing and well stimulation services (7)	16,688	16,688			
Pipeline transportation commitments (8)	55,069	13,323	26,645	15,101	
Rail transportation commitments (9)	51,800	34,587	17,213		
Total contractual obligations	$ 5,301,758	$ 329,448	$ 1,018,393	$ 358,439	$ 3,595,478

(1) Amounts represent scheduled maturities of our senior note obligations at December 31, 2012 and do not reflect any discount or premium at which the senior notes were issued. See *Notes to Consolidated Financial Statements Note 7. Long-Term Debt* for a description of our senior notes.

(2) In February 2012, we borrowed $22 million under a 10-year amortizing term loan secured by our corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan s maturity date of February 26, 2022.

(3) Interest expense includes scheduled cash interest payments on the senior notes and note payable as well as estimated interest payments on our credit facility borrowings outstanding at December 31, 2012 and assumes the actual weighted average interest rate on our credit facility borrowings of 1.7% at December 31, 2012 continues for the life of the credit facility.

(4) Amounts represent estimated discounted costs for future dismantlement and abandonment of our crude oil and natural gas properties. See *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies* for additional discussion.

(5) Operating lease obligations primarily represent leases for office equipment and tanks for storage of hydraulic fracturing fluids. See *Notes to Consolidated Financial Statements Note 9. Lease Commitments* for additional discussion.

(6) We have drilling rig contracts with various terms extending through August 2014. These contracts were entered into in the normal course of business to ensure rig availability to allow us to execute our business objectives in our key strategic plays. These drilling commitments are not recorded in the accompanying consolidated balance sheets.

(7) We have an agreement with a third party whereby the third party will provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of our properties in North Dakota and Montana. The agreement has a term of three years, beginning in October 2010, with two one-year extensions available to us at our discretion. Pursuant to the take-or-pay provisions, we pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether the services are provided. The agreement also stipulates we will bear the cost of certain products and materials used. The commitments under this agreement are not recorded in the accompanying consolidated balance sheets.

(8) We have entered into firm transportation commitments to guarantee pipeline access capacity totaling 15,000 barrels of crude oil per day on operational pipelines in order to reduce the impact of possible production

curtailments that may arise due to limited transportation capacity. The commitments, which have 5-year terms extending as far as November 2017, require us to pay varying per-barrel transportation charges regardless of the amount of pipeline capacity used. Our pipeline commitments are for crude oil production in the North region where we allocate a significant portion of our capital expenditures. These commitments are not recorded in the accompanying consolidated balance sheets.

(9) We have entered into firm transportation commitments to guarantee capacity on rail transportation facilities in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The rail commitments have various terms extending through December 2015 and require us to pay varying per-barrel transportation charges on volumes ranging from 2,500 to 10,000 barrels of crude oil per day regardless of the amount of rail capacity used. Our rail commitments are for crude oil production in the North region where we allocate a significant portion of our capital expenditures. These commitments are not recorded in the accompanying consolidated balance sheets.

In addition to the operational pipeline transportation commitments described above, we are a party to 5-year firm transportation commitments for future pipeline projects being considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require significant additional construction efforts by our counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.0 billion at December 31, 2012, representing aggregate transportation charges expected to be incurred over the 5-year terms of the arrangements assuming the proposed pipeline projects are completed and become operational. The timing of the commencement of pipeline operations is not known due to uncertainties involving matters such as regulatory approvals, resolution of legal and environmental disputes, construction progress and the ultimate probability of pipeline completion. Accordingly, the timing of our obligations under these non-operational arrangements cannot be predicted with certainty and may not be incurred on a ratable basis over a calendar year or may not be incurred at all. Although timing is uncertain, our obligations under these arrangements are not expected to begin until at least 2014.

We are not committed under existing contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Crude Oil and Natural Gas Hedging

As part of our risk management program, we hedge a portion of our anticipated future crude oil and natural gas production to achieve more predictable cash flows and to reduce our exposure to fluctuations in crude oil and natural gas prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions and our desire to have the cash flows needed to fund the development of our inventory of undeveloped crude oil and natural gas reserves in conjunction with our growth strategy. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. Substantially all of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our credit facility. For a discussion of the potential risks associated with our hedging program, refer to *Part I, Item 1A. Risk Factors Our derivative activities could result in financial losses or reduce our earnings.*

Our derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX West Texas Intermediate pricing or Inter-Continental Exchange pricing for Brent crude oil and natural gas derivative settlements based on NYMEX Henry Hub pricing. Please see *Notes to Consolidated Financial Statements Note 5. Derivative Instruments* for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts as of December 31, 2012 and the estimated fair value of those contracts as of that date.

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Between January 1, 2013 and February 15, 2013, we entered into additional derivative contracts summarized in the tables below. None of these contracts have been designated for hedge accounting.

Crude Oil ICE Brent

Period and Type of Contract	Bbls	Weighted Average Price
January 2013 - March 2013		
Swaps - ICE Brent	270,000	$ 107.87
April 2013 - December 2013		
Swaps - ICE Brent	1,100,000	$ 109.27
January 2014 - December 2014		
Swaps - ICE Brent	5,292,500	$ 105.51

Natural Gas NYMEX Henry Hub

Period and Type of Contract	MMBtus	Weighted Average Price
February 2013 - December 2013		
Swaps - Henry Hub	13,360,000	$ 3.66

Common Stock Issued in Exchange for Acquired Assets

On March 27, 2012, we entered into a Reorganization and Purchase and Sale Agreement (the Agreement) with Wheatland Oil Inc. (Wheatland) and the shareholders of Wheatland. Wheatland is owned 75% by the Revocable Inter Vivos Trust of Harold G. Hamm, a trust of which Harold G. Hamm, our Chief Executive Officer, Chairman of the Board and principal shareholder is the trustee and sole beneficiary, and 25% by our Vice Chairman of Strategic Growth Initiatives, Jeffrey B. Hume. The Agreement provided for the acquisition by us, through the issuance of shares of our common stock, of all of Wheatland s right, title and interest in and to certain crude oil and natural gas properties and related assets, in which we also owned an interest, in the states of Mississippi, Montana, North Dakota and Oklahoma and the assumption of certain liabilities related thereto.

A special meeting of our shareholders was held on August 10, 2012 for the purpose of voting on whether to approve the issuance of shares of our common stock pursuant to the Agreement as required by Oklahoma state law, the requirements of the New York Stock Exchange Listed Company Manual and the terms of the Agreement. The proposal to issue shares of our common stock pursuant to the Agreement received the requisite affirmative shareholder votes at the August 10, 2012 special meeting to satisfy the necessary approval requirements. As a result, the Wheatland transaction was consummated and closed on August 13, 2012, with an effective date of January 1, 2012. At closing, after considering customary purchase price adjustments, we issued an aggregate of approximately 3.9 million shares of our common stock, par value $0.01 per share, to the shareholders of Wheatland in accordance with the terms of the Agreement. The fair value of the consideration transferred at closing was approximately $279 million. All purchase price adjustments arising after the closing date as allowed for under the Agreement, which amounted to $0.5 million being owed to the Company by Wheatland, have been agreed upon by the parties and are reflected in our consolidated financial statements at December 31, 2012.

Critical Accounting Policies and Estimates

Our consolidated financial statements and related footnotes 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 our management to 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 existing rules must be done and judgments must be made on how the specifics of a given rule apply to us.

In management s opinion, the most significant reporting areas impacted by management s judgments and estimates are crude oil and natural gas reserve estimations, revenue recognition, the choice of accounting method for crude oil and natural gas activities and derivatives, impairment of assets and income taxes. 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.

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

Our external independent reserve engineers and internal technical staff prepare the estimates of our crude oil and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of crude oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain. Even though our external independent reserve engineers and internal 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 take into account recent production levels and other technical information about each of our fields. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. 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, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depreciation, depletion, and amortization and may result in material impairments of assets.

Revenue Recognition

We derive substantially all of our revenues from the sale of crude oil and natural gas. Crude oil and natural 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 revenues and actual amounts are recorded in the month payment is received and are reflected in our consolidated statements of income as crude oil and natural gas sales. These variances have historically not been material.

Successful Efforts Method of Accounting

We use the successful efforts method of accounting for our crude oil and natural gas properties, whereby costs incurred to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells, and expenditures for enhanced recovery operations are capitalized. Geological and geophysical costs, seismic costs incurred for exploratory projects, lease rentals and costs associated with unsuccessful exploratory wells or projects are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. To the extent a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between capitalized development costs and exploration expense. Maintenance, repairs and costs of injection are expensed as incurred, except that the costs of replacements or renewals that expand capacity or improve production are capitalized.

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Depreciation, depletion, and amortization of capitalized drilling and development costs of crude oil and natural gas properties, including related support equipment and facilities, are generally computed using the unit-of-production method on a field basis based on total estimated proved developed crude oil and natural gas reserves. Amortization of producing leaseholds 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 crude oil and natural gas reserves are established based on estimates made by our internal geologists and engineers and external independent reserve engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 3 to 40 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss, if any, is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least in conjunction with semi-annual reserve reports. Revisions are accounted for prospectively as changes in accounting estimates.

Derivative Activities

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future crude oil and natural gas production. In addition, we may utilize basis contracts to hedge the differential between NYMEX posted prices and those of our physical pricing points. We do not use derivative instruments for trading purposes. Under accounting rules, we may elect to designate those derivatives that qualify for hedge accounting as cash flow hedges against the price we will receive for our future crude oil and natural gas production. We have elected not to designate any of our price risk management activities as cash flow hedges. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value in current earnings. As such, we are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis on our consolidated balance sheets.

In determining the amounts to be recorded for our open derivative contracts, we are required to estimate the fair value of the derivatives. We use an independent third party to provide our derivative valuations. The third party s valuation models for derivative contracts are industry-standard models that consider various inputs including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The calculation of the fair value of our collar contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the derivative agreements and the resulting estimated future cash inflows or outflows over the lives of the derivatives are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates. We validate our derivative valuations through management review and by comparison to our counterparties valuations for reasonableness.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves.

For producing properties, the evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for crude oil and natural gas, future costs to produce those products, estimates of future crude 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 crude 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 are 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.

Non-producing crude oil and natural gas properties, which consist primarily of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves, are assessed for impairment on a property-by-property basis for individually significant balances, if any, and on an aggregate basis by prospect for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level consistent with the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms, and potential shifts in business strategy employed by management. For individually insignificant non-producing properties, impairment losses are recognized by amortizing the portion of the properties costs which management estimates will not be transferred to proved properties over the lives of the leases based on experience of successful drilling and the average holding period. The estimated rate of successful drilling is highly judgmental and is subject to material revision in future periods as better information becomes available.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain deferred tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets. If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2012, we believe all deferred tax assets recorded on our consolidated balance sheets will ultimately be utilized. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly related to prevailing crude oil and natural gas prices). If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision could increase in the period it is determined that it is more likely than not that a deferred tax asset will not be utilized.

Our effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax-paying companies. Our effective tax rate is affected by changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state. Due to the size of our gross deferred tax balances, a small change in our estimated future tax rate can have a material effect on current period earnings.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resources. However, as is customary in the crude oil and natural gas industry, we have various contractual commitments that are not reflected in the consolidated balance sheets as shown under *Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations.*

Recent Accounting Pronouncement Not Yet Adopted

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities*. The new standard requires an entity to disclose information about offsetting arrangements to enable financial statement users to understand the effect of netting arrangements on an entity s financial position. The disclosures are required for recognized financial instruments and derivative instruments that are subject to offsetting under current accounting literature or are subject to master netting arrangements irrespective of whether they are offset. The objective of the new disclosures is to facilitate comparison between entities that prepare financial statements on the basis of U.S. GAAP and entities that prepare financial statements under International Financial Reporting Standards. The disclosure requirements are effective for periods beginning on or after January 1, 2013 and must be applied retrospectively to all periods presented on the balance sheet. We will adopt the requirements of ASU No. 2011-11 with the preparation of our Form 10-Q for the quarter ending March 31, 2013, which will require additional footnote disclosures for our derivative instruments and are not expected to have a material effect on our financial position, results of operations or cash flows.

We are monitoring the joint standard-setting efforts of the FASB and International Accounting Standards Board. There are a number of pending accounting standards being targeted for completion in 2013 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, and accounting for financial instruments. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact these standards will have, if any, on our financial position, results of operations or cash flows.

Pending Legislative and Regulatory Initiatives

The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. Laws, rules, regulations, policies, and interpretations affecting the crude oil and natural gas industry have been pervasive and are continuously reviewed by legislators and regulators, including the imposition of new or increased requirements on us and other industry participants. Following is a discussion of significant laws and regulations that have been enacted or are currently being considered by regulatory bodies that may affect us in the areas in which we operate.

Hydraulic fracturing. Some activists have attempted to link hydraulic fracturing to various environmental problems, including adverse effects to drinking water supplies and migration of methane and other hydrocarbons. As a result, several federal agencies are studying the environmental risks with respect to hydraulic fracturing or evaluating whether to restrict its use. From time to time, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection, thereby requiring the crude oil and natural gas industry to obtain permits for hydraulic fracturing and to require disclosure of the additives used in the process. If adopted, such legislation could establish an additional level of regulation and permitting at the federal level. Scrutiny of hydraulic fracturing activities continues in other ways. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a number of federal agencies are analyzing environmental issues associated with hydraulic fracturing. The EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the draft results of which are anticipated to be available in 2014. Further, on May 11, 2012, the Bureau of Land Management (BLM) issued a proposed rule that would require public disclosure of chemicals used in hydraulic fracturing operations, and impose other operational requirements for all hydraulic fracturing operations on federal lands, including Native American trust lands. The Department of the Interior announced on January 18, 2013 that the BLM will issue a revised draft rule by March 31, 2013. In addition to these federal initiatives, several state and local governments, including states in which we operate, have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. We voluntarily participate in FracFocus, a national publicly accessible Internet-based registry developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. This registry, located at *www.fracfocus.org*, provides our industry with an avenue to voluntarily disclose additives used in the hydraulic fracturing process. We currently disclose the additives used in the hydraulic fracturing process on all wells we operate.

The adoption of any future federal, state or local laws or implementing regulations imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations, increase our costs of compliance and doing business, and delay, prevent or prohibit the development of natural resources from unconventional formations. Compliance, or the consequences of any failure to comply by us, could have a material adverse effect on our financial condition and results of operations. At this time it is not possible to estimate the potential impact on our business if any such federal or state legislation is enacted into law.

Climate change. Federal, state and local laws and regulations are increasingly being enacted to address concerns about the effects the emission of carbon dioxide and other identified greenhouse gases may have on the environment and climate worldwide. These effects are widely referred to as climate change. Since its December 2009 endangerment finding regarding the emission of carbon dioxide, methane and other greenhouse gases, the EPA has begun regulating sources of greenhouse gas emissions under the federal Clean Air Act. Among several regulations requiring reporting or permitting for greenhouse gas sources, the EPA finalized its tailoring rule in May 2010 that identifies which stationary sources of greenhouse gases are required to obtain permits to construct, modify or operate on account of, and to implement the best available control technology for, their greenhouse gases. In November 2010, the EPA also finalized its greenhouse gas reporting requirements for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires annual reporting to the EPA of greenhouse gas emissions by such regulated facilities.

Moreover, in recent years the U.S. Congress has considered establishing a cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Under past proposals, the EPA would issue or sell a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of such legislation, if adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. In addition, while the prospect for such cap-and-trade legislation by the U.S. Congress remains uncertain, several states, including states in which we operate, have adopted, or are in the process of adopting, similar cap-and-trade programs.

As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop and produce crude oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the crude oil and natural gas we sell, emits carbon dioxide and other greenhouse gases. Thus, any current or future federal, state or local climate change initiatives could adversely affect demand for the crude oil and natural gas we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels, and therefore could have a material adverse effect on our business. Although our compliance with any greenhouse gas regulations may result in increased compliance and operating costs, we do not expect the compliance costs for currently applicable regulations to be material. Moreover, while it is not possible at this time to estimate the compliance costs or operational impacts for any new legislative or regulatory developments in this area, we do not anticipate being impacted to any greater degree than other similarly situated competitors.

For a discussion of our environmental protection initiatives, particularly with respect to our efforts to reduce flaring of natural gas, see *Part I, Item 1. Regulation of the Crude Oil and Natural Gas Industry Environmental, Health and Safety Regulation.*

Dodd-Frank Wall Street Reform and Consumer Protection Act. In July 2010, the Dodd-Frank Act was enacted into law. This financial reform legislation includes provisions that require derivative transactions that are currently executed over-the-counter to be executed through an exchange and be centrally cleared. The Dodd-Frank Act requires the CFTC, the SEC, and other regulators to establish rules and regulations to implement the new legislation. The CFTC has issued final regulations to implement significant aspects of the legislation, including new rules for the registration of swap dealers and major swap participants (and related definitions of those terms), definitions of the term swap, rules to establish the ability to rely on the commercial end-user exception from the central clearing and exchange trading requirements, requirements for reporting and recordkeeping, rules on customer protection in the context of cleared swaps, and position limits for swaps and other transactions based on the price of certain reference contracts, some of which are referenced in our swap contracts. The position limits regulation has been vacated by a Federal court, and the CFTC is appealing that decision; accordingly, the effective date of these rules, if they are reinstated on appeal, or of replacement rules proposed and adopted by the CFTC, if applicable, is not currently known. Key regulations that have not yet been finalized include those establishing margin requirements for uncleared swaps, regulatory capital requirements for swap dealers and various trade execution requirements.

On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and certain index credit default swaps and setting compliance dates for different categories of market participants, the earliest of which is March 11, 2013. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. Although we expect to qualify for the end-user exception from the clearing requirement for our swaps, mandatory clearing requirements and revised capital requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for hedging.

The CFTC s swap regulations may require or cause our counterparties to collect margin from us, and if any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap execution facility. The ultimate effect of the proposed new rules and any additional regulations on our business is uncertain. Of particular concern is whether our status as a commercial end-user will allow our derivative counterparties to not require us to post margin in connection with our commodity price risk management activities. The remaining final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area, to the extent applicable to us or our derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial and commercial risks related to fluctuations in commodity prices. Additional effects of the new regulations, including increased regulatory reporting and recordkeeping costs, increased regulatory capital requirements for our counterparties, and market dislocations or disruptions, among other consequences, could have an adverse effect on our ability to hedge risks associated with our business.

Additionally, in August 2012 the SEC adopted the Dodd-Frank Act requirement that registrants disclose certain payments made to the U.S. Federal government and foreign governments in connection with the commercial development of crude oil, natural gas or minerals. The deadline for implementing the new disclosures is May 31, 2014 for applicable payments made during the period from October 1, 2013 to December 31, 2013. We are working to develop a responsive approach for complying with the new disclosure requirements by the required deadline. We are also monitoring our operations to determine if any disclosure or reporting obligations arise under the conflict mineral rules established under the Dodd-Frank Act.

Inflation

In recent years we have experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increases in drilling activity, particularly in the North region, and competitive pressures resulting from higher crude oil prices and may again in the future.

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Non-GAAP Financial Measures

EBITDAX

We present EBITDAX throughout this Annual Report on Form 10-K, which is a non-GAAP financial measure. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income and operating cash flows in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

EBITDAX should not be considered as an alternative to, or more meaningful than, net income or operating cash flows as determined in accordance with U.S. 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 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 funded debt to EBITDAX ratio of no greater than 4.0 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and letters of credit under our credit facility plus our note payable and Senior Note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with this covenant at December 31, 2012. At that date, our total funded debt to EBITDAX ratio was 1.8 to 1.0. A violation of this covenant in the future could result in a default under our credit facility and such event could result in an acceleration of other outstanding indebtedness. In the event of such default, the lenders under our credit facility could elect to terminate their commitments thereunder, cease making further loans, and could declare all outstanding amounts, if any, to be due and payable. If we had any outstanding borrowings under our credit facility and such indebtedness were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us.

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The following table provides a reconciliation of our net income to EBITDAX for the periods presented.

in thousands	Year Ended December 31, 2012	2011	2010	2009	2008
Net income	$ 739,385	$ 429,072	$ 168,255	$ 71,338	$ 320,950
Interest expense	140,708	76,722	53,147	23,232	12,188
Provision for income taxes	415,811	258,373	90,212	38,670	197,580
Depreciation, depletion, amortization and accretion	692,118	390,899	243,601	207,602	148,902
Property impairments	122,274	108,458	64,951	83,694	28,847
Exploration expenses	23,507	27,920	12,763	12,615	40,160
Impact from derivative instruments:					
Total (gain) loss on derivatives, net	(154,016)	30,049	130,762	1,520	7,966
Total realized gain (loss) (cash flow) on derivatives, net	(45,721)	(34,106)	35,495	569	(7,966)
Non-cash (gain) loss on derivatives, net	(199,737)	(4,057)	166,257	2,089	
Non-cash equity compensation	29,057	16,572	11,691	11,408	9,081
EBITDAX	$ 1,963,123	$ 1,303,959	$ 810,877	$ 450,648	$ 757,708

The following table provides a reconciliation of our net cash provided by operating activities to EBITDAX for the periods presented.

in thousands	Year Ended December 31, 2012	2011	2010	2009	2008
Net cash provided by operating activities	$ 1,632,065	$ 1,067,915	$ 653,167	$ 372,986	$ 719,915
Current income tax provision	10,517	13,170	12,853	2,551	13,465
Interest expense	140,708	76,722	53,147	23,232	12,188
Exploration expenses, excluding dry hole costs	22,740	19,971	9,739	6,138	20,158
Gain on sale of assets, net	136,047	20,838	29,588	709	894
Excess tax benefit from stock-based compensation	15,618		5,230	2,872	
Other, net	(7,587)	(4,606)	(3,513)	(3,890)	26,252
Changes in assets and liabilities	13,015	109,949	50,666	46,050	(35,164)
EBITDAX	$ 1,963,123	$ 1,303,959	$ 810,877	$ 450,648	$ 757,708

PV-10

Our PV-10 value, a non-GAAP financial measure, is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 generally differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. At December 31, 2012, our PV-10 totaled approximately $13.3 billion. The Standardized Measure of our discounted future net cash flows was approximately $11.2 billion at December 31, 2012, representing a $2.1 billion difference from PV-10 because of the income tax effect. We believe the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk. Our primary market risk exposure is in the pricing applicable to our crude oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for crude oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price. Based on our average daily production for the year ended December 31, 2012 and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $250 million for each $10.00 per barrel change in crude oil prices and $64 million for each $1.00 per Mcf change in natural gas prices.

To reduce price risk caused by these market fluctuations, we periodically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure we have adequate funds available for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While hedging limits the downside risk of adverse price movements, it also limits future revenues from upward price movements.

Changes in commodity futures price strips during the year ended December 31, 2012 had an overall net positive impact on the fair value of our derivative contracts. For the year ended December 31, 2012, we reported an unrealized non-cash mark-to-market gain on derivatives of $199.7 million, the financial impact of which was partially offset by realized losses on derivatives of $45.7 million. The fair value of our derivative instruments at December 31, 2012 was a net asset of $35.4 million. This mark-to-market net asset relates to derivative instruments with various terms that are scheduled to be realized over the period from January 2013 through December 2015. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at December 31, 2012. An assumed increase in the forward commodity prices used in the year-end valuation of our derivative instruments of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would change our derivative valuation to a net liability of approximately $398 million at December 31, 2012. Conversely, an assumed decrease in forward commodity prices of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would increase our net derivative asset to approximately $461 million at December 31, 2012.

For a further discussion of our hedging activities, see *Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Crude Oil and Natural Gas Hedging* and *Part II, Item 8. Notes to Consolidated Financial Statements Note 5. Derivative Instruments* appearing in this Annual Report.

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 crude oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($480.3 million in receivables at December 31, 2012), our joint interest receivables ($356.8 million at December 31, 2012), and counterparty credit risk associated with our derivative instrument receivables ($50.6 million at December 31, 2012).

We monitor our exposure to counterparties on crude oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. We have not generally required our counterparties to provide collateral to support crude oil and natural gas sales receivables owed to us. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

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Joint interest receivables arise from billing entities which own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $30.4 million as of December 31, 2012, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We also have the right to place a lien on our co-owners interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty. Substantially all of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our credit facility.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to variable-rate borrowings outstanding under our credit facility. We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest expense related to existing debt issues. Interest rate derivatives may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives. We had $840 million of outstanding borrowings under our credit facility at February 15, 2013. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $8.4 million per year and a $5.2 million decrease in net income per year. Our credit facility matures on July 1, 2015 and the weighted-average interest rate on outstanding borrowings at February 15, 2013 was 2.0%.

The following table presents our debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2012:

In thousands	2013	2014	2015	2016	2017	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)	$	$	$	$	$	$ 2,900,000	$ 2,900,000
Weighted-average interest rate						5.8%	5.8%
Note payable:							
Principal amount	$ 1,950	$ 2,013	$ 2,078	$ 2,144	$ 2,214	$ 10,022	$ 20,421
Interest rate	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%
Variable rate debt:							
Revolving credit facility:							
Principal amount	$	$	$ 595,000	$	$	$	$ 595,000
Weighted-average interest rate			1.7%				1.7%

(1) Amount does not reflect any discount or premium at which the senior notes were issued.

Changes in interest rates affect the amounts we pay on borrowings under our credit facility. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair values of our senior notes and note payable.

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Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

Continental Resources, Inc.

We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. (an Oklahoma corporation) and Subsidiaries (the Company) as of December 31, 2012 and 2011, and the related consolidated statements of income, shareholders equity and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Continental Resources, Inc. and Subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 27, 2013 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 27, 2013

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Continental Resources, Inc. and Subsidiaries

Consolidated Balance Sheets

	December 31, 2012	December 31, 2011
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 35,729	$ 53,544
Receivables:		
Crude oil and natural gas sales	468,650	366,441
Affiliated parties	12,410	31,108
Joint interest and other, net	356,111	379,991
Derivative assets	18,389	6,669
Inventories	46,743	41,270
Deferred and prepaid taxes	365	47,658
Prepaid expenses and other	8,386	9,692
Total current assets	946,783	936,373
Net property and equipment, based on successful efforts method of accounting	8,105,269	4,681,733
Net debt issuance costs and other	55,726	24,355
Noncurrent derivative assets	32,231	3,625
Total assets	$ 9,140,009	$ 5,646,086
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 687,310	$ 642,889
Revenues and royalties payable	261,856	222,027
Payables to affiliated parties	6,069	9,939
Accrued liabilities and other	153,454	117,674
Derivative liabilities	12,999	116,985
Current portion of asset retirement obligations	2,227	2,287
Current portion of long-term debt	1,950	
Total current liabilities	1,125,865	1,111,801
Long-term debt, net of current portion	3,537,771	1,254,301
Other noncurrent liabilities:		
Deferred income tax liabilities	1,262,576	850,282
Asset retirement obligations, net of current portion	44,944	60,338
Noncurrent derivative liabilities	2,173	57,598
Other noncurrent liabilities	2,981	3,640
Total other noncurrent liabilities	1,312,674	971,858
Commitments and contingencies (Note 10)		
Shareholders equity:		
Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding		
Common stock, $0.01 par value; 500,000,000 shares authorized; 185,604,681 shares issued and outstanding at December 31, 2012; 180,871,688 shares issued and outstanding at December 31, 2011	1,856	1,809
Additional paid-in capital	1,226,835	1,110,694

Retained earnings	1,935,008	1,195,623
Total shareholders equity	3,163,699	2,308,126
Total liabilities and shareholders equity	$ 9,140,009	$ 5,646,086

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

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Continental Resources, Inc. and Subsidiaries

Consolidated Statements of Income

	Year Ended December 31,		
	2012	2011	2010
	In thousands, except per share data		
Revenues:			
Crude oil and natural gas sales	$ 2,315,840	$ 1,553,629	$ 917,503
Crude oil and natural gas sales to affiliates	63,593	93,790	31,021
Gain (loss) on derivative instruments, net	154,016	(30,049)	(130,762)
Crude oil and natural gas service operations	39,071	32,419	21,303
Total revenues	2,572,520	1,649,789	839,065
Operating costs and expenses:			
Production expenses	193,466	135,178	86,557
Production and other expenses to affiliates	6,675	4,632	6,646
Production taxes and other expenses	223,737	143,236	76,659
Exploration expenses	23,507	27,920	12,763
Crude oil and natural gas service operations	32,248	26,735	18,065
Depreciation, depletion, amortization and accretion	692,118	390,899	243,601
Property impairments	122,274	108,458	64,951
General and administrative expenses	121,735	72,817	49,090
Gain on sale of assets, net	(136,047)	(20,838)	(29,588)
Total operating costs and expenses	1,279,713	889,037	528,744
Income from operations	1,292,807	760,752	310,321
Other income (expense):			
Interest expense	(140,708)	(76,722)	(53,147)
Other	3,097	3,415	1,293
	(137,611)	(73,307)	(51,854)
Income before income taxes	1,155,196	687,445	258,467
Provision for income taxes	415,811	258,373	90,212
Net income	$ 739,385	$ 429,072	$ 168,255
Basic net income per share	$ 4.08	$ 2.42	$ 1.00
Diluted net income per share	$ 4.07	$ 2.41	&nb