CONTINENTAL RESOURCES INC
Form 10-K
February 27, 2009
Table of Contents

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, 2008

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number: 001-32886

CONTINENTAL RESOURCES, INC.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

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

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

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

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked prices of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter. As of June 30, 2008 aggregate market value was $3,138,228,490.

As of February 23, 2009, the registrant had 169,556,833 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Continental Resources, Inc. for the Annual Meeting of Stockholders to be held May 28, 2009, which will be filed with the Commission no later than April 30, 2009 are incorporated by reference into Part III of this Form 10-K.

Table of Contents

Table of Contents

Table of Contents

Glossary of Oil and Natural Gas Terms

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

AMI. Area of mutual interest.

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.

Bcfe. One billion cubic feet of natural gas equivalent with one barrel of oil converted to six thousand cubic feet of natural gas.

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

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

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

DD&A. Depreciation, depletion, amortization and accretion.

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

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

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

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

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

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

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

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

HPAI. High pressure air injection.

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

Table of Contents

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

Mcf. One thousand cubic feet of natural gas.

MBoe. One thousand Boe.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

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

PUD. Proved undeveloped.

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV-10 is 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 our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

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

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

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

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

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

Simul-Frac. Simultaneously fracture treating two or more wells within the same fracture plane in order to create pressure interference between the wells and thereby increasing the stimulated reservoir volume.

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

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

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

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

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

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

Cautionary Statement Regarding Forward-Looking Statements

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Except as otherwise specifically indicated, these statements assume no significant changes will occur in the operating environment for oil and natural gas properties and that there will be no material acquisitions, divestitures or financings except as otherwise described.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- financial strategy;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;

competition and government regulations;

marketing of oil and natural gas;

exploitation or property acquisitions;

Table of Contents

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

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

Table of Contents

Part I

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

Item 1. Business

General

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We were originally formed in 1967 to explore, develop and produce oil and natural gas properties. Through 1993, our activities and growth remained focused primarily in Oklahoma. In 1993, we expanded our activity into the Rocky Mountain and Gulf Coast regions. Approximately 70% of our estimated proved reserves as of December 31, 2008 are located in the Rocky Mountain region. We completed an initial public offering of our common stock on May 14, 2007, and our common stock began trading on the New York Stock Exchange on May 15, 2007 under the ticker symbol CLR .

We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 121.7 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2004 through December 31, 2008 compared to 3.1 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2008, our estimated proved reserves were 159.3 MMBoe, with estimated proved developed reserves of 106.0 MMBoe, or 67% of our total estimated proved reserves. Crude oil comprised 67% of our total estimated proved reserves. For the year ended December 31, 2008, we generated revenues of $960.5 million and operating cash flows of $719.9 million. For the year and quarter ended December 31, 2008, daily production averaged 32,803 and 36,018 Boe per day, respectively. This represents growth of 13% and 19% as compared to the year and quarter ended December 31, 2007, when daily production averaged 29,099 Boe and 30,369 Boe, respectively.

Table of Contents

The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2008, average daily production for the three months ended December 31, 2008 and the reserve-to-production index in our principal regions. Our reserve estimates as of December 31, 2008 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10. Our technical staff evaluated properties representing the remaining 17% of our PV-10.

	At December 31, 2008				Average daily production fourth quarter 2008 (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)]
Rockies:							
Red River units	59,386	37.3%	$ 697	242	14,058	39.0%	11.5
Bakken field							
Montana Bakken	28,228	17.7%	240	100	6,410	17.8%	12.0
North Dakota Bakken	17,507	11.0%	160	48	4,401	12.2%	10.9
Other	6,900	4.3%	62	272	2,508	7.0%	7.5
Mid-Continent:							
Arkoma Woodford	30,749	19.3%	184	42	3,276	9.1%	25.6
Other	16,062	10.1%	170	752	4,750	13.2%	9.2
Gulf Coast	430	0.3%	10	17	615	1.7%	1.9
Total	159,262	100.0%	$ 1,523	1,473	36,018	100.0%	12.1

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. The Standardized Measure at December 31, 2008 is $1.3 billion, a $0.2 billion difference from PV-10 because of the tax effect. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2008 production into the proved reserve quantity at December 31, 2008.

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

	Developed acres		Undeveloped acres		Gross wells planned for drilling	Capital expenditures (in millions)[(1)]
	Gross	Net	Gross	Net		
Rockies:						
Red River units	147,235	131,320			4	$ 46
Bakken field						
Montana Bakken	82,182	64,438	131,422	101,010		7
North Dakota Bakken	76,337	37,135	865,116	378,425	86	72
Other	61,963	46,818	309,741	189,818	2	2
Mid-Continent:						
Arkoma Woodford	61,461	13,288	99,158	33,568	63	56
Other	138,437	95,093	584,215	382,377	19	27
Gulf Coast	40,748	11,733	36,304	29,247		1
Total	608,363	399,825	2,025,956	1,114,445	174	$ 211

(1) Capital expenditures budgeted for 2009 includes amounts for drilling, capital workovers and facilities and excludes amounts for land of $54 million, seismic of $4 million, and $6 million for vehicles, computers and other equipment. While the above capital expenditures budget reflects our current intentions, we intend to manage our 2009 capital expenditures to be inline with our cash flow from operations. Continued weakness in 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 Oil. During the late 1980 s we began to believe that the valuation potential for crude oil exceeded that of natural gas. Accordingly, we began to shift our reserve and production profiles towards crude oil. As of December 31, 2008, crude oil comprises 67% of our total proved reserves and 76% of our 2008 annual production. Although we do pursue natural gas opportunities, we continue to believe that crude oil valuations will be superior to natural gas valuations on a relative Btu basis.

Growth Through Low-Cost Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions. From January 1, 2004 through December 31, 2008, proved oil and natural gas reserve additions through extensions and discoveries were 121.7 MMBoe compared to 3.1 MMBoe of proved reserve purchases.

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

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite, Bakken Shale and Arkoma Woodford formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technology. Our production from the Red River units, the Bakken field, and the Arkoma Woodford comprised approximately 9,302 MBoe, or 77% of our total oil and natural gas production during the year ended December 31, 2008.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 513,003 net undeveloped acres held in the Montana and North Dakota Bakken shale and Arkoma Woodford fields, we held 359,120 net undeveloped acres in other oil and natural gas shale plays as of December 31, 2008. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

Our Business Strengths

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

Large Acreage Inventory. We own 1,114,445 net undeveloped and 399,825 net developed acres as of December 31, 2008. Approximately 78% of the undeveloped acres are located within unconventional shale resource plays including the Bakken shale in North Dakota and Montana, the Woodford shale in southeast and western Oklahoma, the Atoka shale in western Oklahoma and the Texas Panhandle, the New Albany shale in Indiana and Kentucky and the Lower Huron, Rhinestreet and Marcellus shales in West Virginia, Pennsylvania, New York and Ohio. The balance of the undeveloped acreage is located primarily in conventional plays including 3D defined locations for the Trenton-Black River of Michigan, Red River of Montana and North Dakota, Morrow-Springer of western Oklahoma and Frio in South Texas.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 600 horizontal wells since that time. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 48 waterflood units. Additionally, we operate eight high pressure air injection (HPAI) floods.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2008, we operated properties comprising 91% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our seven senior officers have an average of 28 years of oil and gas industry experience. Additionally, our technical staff, which includes 27 petroleum engineers, 17 geoscientists and 11 landmen, has an average of 20 years experience in the industry.

Strong Financial Position. As of February 23, 2009, we had outstanding borrowings under our revolving credit facility of approximately $474.4 million and available borrowing capacity under our selected commitment level of $198.1 million. We have elected to set the commitment level at $672.5 million, which is below the revolving credit facility note amount of $750.0 million and the established borrowing base of $850.0 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows and borrowings under our revolving credit facility. Our 2009 capital expenditures budget has been established based on our current expectation of available cash flow from operations. Should expected available cash flow from operations materially vary from expectations, we believe our credit facility has sufficient availability to fund any deficit or that we can further reduce our capital expenditures to be in line with cash flow from operations.

Oil and Gas Operations

Proved Reserves

The following tables set forth our estimated proved oil and natural gas reserves, percent of total proved reserves that are proved developed, the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2008 by reserve category and region. Ryder Scott Company, L.P., our independent petroleum engineers, evaluated properties representing approximately 83% of our PV-10, and our technical staff evaluated the remaining properties. The year-end weighted average oil and natural gas prices used in the computation of future net cash flows at December 31, 2008 were $39.69 per barrel and $4.90 per Mcf, respectively.

	December 31, 2008			
	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	PV-10[1] (in millions)
Proved developed producing	79,845	153,038	105,351	$ 1,267
Proved developed non-producing	542	498	625	5
Proved undeveloped	25,852	164,602	53,286	251
Total proved reserves	106,239	318,138	159,262	$ 1,523
Standardized measure				$ 1,277

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	% Proved developed	PV-10[1] (in millions)
Rockies:					
Red River units	54,917	26,812	59,386	85%	$ 697
Bakken field					
Montana Bakken	24,154	24,443	28,228	64%	240
North Dakota Bakken	14,832	16,047	17,507	52%	160
Other	5,524	8,255	6,900	99%	62
Mid-Continent:					
Arkoma Woodford	62	184,120	30,749	24%	184
Other	6,657	56,439	16,062	86%	170
Gulf Coast	93	2,022	430	100%	10
Total	106,239	318,138	159,262	67%	$ 1,523

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. The Standardized Measure at December 31, 2008 is $1.3 billion, a $0.2 billion difference from PV-10 because of the tax effect. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2008:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units	147,235	131,320			147,235	131,320
Bakken field						
Montana Bakken	82,182	64,438	131,422	101,010	213,604	165,448
North Dakota Bakken	76,337	37,135	865,116	378,425	941,453	415,560
Other	61,963	46,818	309,741	189,818	371,704	236,636
Mid-Continent:						
Arkoma Woodford	61,461	13,288	99,158	33,568	160,619	46,856
Other	138,437	95,093	584,215	382,377	722,652	477,470
Gulf Coast	40,748	11,733	36,304	29,247	77,052	40,980
Total	608,363	399,825	2,025,956	1,114,445	2,634,319	1,514,270

Table of Contents

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2008 that will expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2009		2010		2011	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units						
Bakken field						
Montana Bakken	18,037	10,920	24,557	19,510	57,527	48,367
North Dakota Bakken	156,404	83,394	137,899	59,424	224,552	79,934
Other	49,311	20,334	37,656	20,141	56,662	41,995
Mid-Continent:						
Arkoma Woodford	49,015	17,005	23,808	8,801	15,225	6,811
Other	24,848	18,009	207,604	113,643	236,500	157,324
Gulf Coast	3,200	2,443	5	3	29,586	25,692
Total	300,815	152,105	431,529	221,522	620,052	360,123

Drilling Activity

During the three years ended December 31, 2008, we drilled exploratory and development wells as set forth in the table below:

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Oil	41	18.2	33	15.6	17	8.4
Natural gas	73	19.5	79	13.1	25	4.9
Dry	12	8.9	4	2.5	17	9.4
Total exploratory wells	126	46.6	116	31.2	59	22.7
Development wells:						
Oil	153	89.3	92	69.5	83	57.0
Natural gas	72	13.4	49	10.3	34	14.5
Dry	8	3.2	5	1.1	7	4.3
Total development wells	233	105.9	146	80.9	124	75.8
Total wells	359	152.5	262	112.1	183	98.5

As of December 31, 2008, there were 117 gross (40 net) wells in the process of drilling, completing or waiting on completion.

As of February 23, 2009, we operated 7 rigs on our properties. Our rig activity during 2009 will be highly dependent on 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 Risk Factors The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Summary of Oil and Natural Gas Properties and Projects

Throughout the following discussion, we discuss our budgeted number of wells and capital expenditures. While the discussion reflects our current intentions, we intend to manage 2009 capital expenditures to be inline with our cash flow from operations. Continued weakness in 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.

6

Table of Contents

Rocky Mountain Region

Our properties in the Rocky Mountain region represented 76% of our PV-10 as of December 31, 2008. During the three months ended December 31, 2008, our average daily production from such properties was 24,536 net Bbls of oil and 17,041 net Mcf of natural gas. Our principal producing properties in this region are in the Red River units, the Bakken field and the Big Horn Basin.

Red River Units

Our Red River units represented 59.6% of our PV-10 in the Rocky Mountain region as of December 31, 2008 and 51% of our average daily Rocky Mountain region Boe production for the three months ended December 31, 2008. The eight units comprising the Red River units are located along the Cedar Creek Anticline in North Dakota, South Dakota and Montana and produce oil and natural gas from the Red River B formation, a thin, continuous, dolomite formation at depths of 8,000 to 9,500 feet. Our Red River units comprise a portion of the Cedar Hills field, listed by the Energy Information Administration in 2007 as the 6th largest onshore, lower 48 field in the United States ranked by liquid proved reserves.

Cedar Hills Units. The Cedar Hills North unit (CHNU) is located in Bowman and Slope Counties, North Dakota. We drilled the initial horizontal well in the CHNU, the Ponderosa 1-15, in April 1995. As of December 31, 2008, we had drilled 225 horizontal wells within this 49,700-acre unit, with 128 producing wellbores and the remainder serving as injection wellbores. We operate and own a 98% working interest in the CHNU.

The Cedar Hills West unit (CHWU), in Fallon County, Montana, is contiguous to the northern portion of CHNU. As of December 31, 2008, this 7,800-acre unit contained eleven horizontal producing wells and six horizontal injection wells. We operate and own a 100% working interest in the CHWU.

In January 2003, we commenced enhanced recovery in the two Cedar Hills units, with HPAI used throughout most of the area and water injected generally along the boundary of the CHNU. Under HPAI, compressed air injected into a reservoir oxidizes residual oil and produces flue gases (primarily carbon dioxide and nitrogen) that mobilize and sweep the crude oil into producing wellbores. In response to the HPAI, water injection and increased density drilling operations, production from the Cedar Hills units increased to 11,451 net Boe per day in December 2008 from 2,185 net Boe per day in November 2003. As of December 31, 2008, the average density in the Cedar Hill units was approximately one producing wellbore per 420 acres. We currently plan to drill 4 new horizontal wellbores and 2 horizontal extensions of existing wellbores in the Cedar Hills units during 2009, increasing the density of both the producing and injection wellbores. The reduced distance between wells allows part of the field to be converted from air injection to water injection. This conversion began in 2008 and is forecast to lower operating expenses, as water is less costly to inject than air. In 2009, we plan to invest approximately $41.3 million drilling and improving facilities in the Cedar Hills units. This expenditure is lower than previously forecast due to the elimination of 25 gross wells from the increased density development program. This adjustment to the plan is a result of reduced commodity prices. The peak rate for the field will be reduced but we expect no reduction in ultimate reserves.

On August 22, 2007 the Hiland Partners, LP (Hiland) Badlands gas plant became operational for the processing and treatment of gas produced from the CHNU, CHWU and Medicine Pole Hills Unit. Under the terms of the November 8, 2005 contract we deliver low pressure gas to Hiland for compression, treatment and processing. Nitrogen and carbon dioxide must be removed from the gas production associated with oil production from the units for the gas production to be marketable. We pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. During December 2008, we sold 7,800 net Mcf of natural gas per day from the Cedar Hills Units.

Medicine Pole Hills Units. The Medicine Pole Hills units (MPHU) are approximately five miles east of the southern portion of the CHNU. We acquired the Medicine Pole Hills unit in 1995. At that time, the 9,600-

Table of Contents

acre unit consisted of 18 vertical producing wellbores and four injection wellbores under HPAI producing 525 net Bbls of oil per day. We have since drilled 47 horizontal wellbores extending production to the west with the formation of the 15,000-acre Medicine Pole Hills West unit and to the south, with the 11,500-acre Medicine Pole Hills South unit. All three units are under HPAI. We operate and own an average 77% working interest in the three units. Production from the units averaged 1,391 net Bbls of oil and 178 net Mcf of natural gas per day during December 2008. During 2008 we drilled 7 new horizontal wellbores, 2 horizontal extensions of existing wellbores, and 2 horizontal re-entries of vertical wellbores, increasing the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. In 2009, we plan to invest approximately $3.4 million for capital workover and facilities in MPHU.

Buffalo Red River Units. Three contiguous Buffalo Red River units (Buffalo, West Buffalo and South Buffalo) are located in Harding County, South Dakota, approximately 21 miles south of the MPHU. When we purchased the units in 1995, there were 73 vertical producing wellbores and 38 injection wellbores under HPAI producing approximately 1,906 net Bbls of oil per day. We operate and own an average working interest of 95% in the 32,900 acres comprising the three units. From 2005 through 2008, we re-entered 48 existing vertical wells and drilled horizontal laterals to increase production and sweep efficiency from the three units. Production for the month of December 2008 was 1,670 net Bbls of oil per day compared to an average of 1,162 net Bbls of oil per day for the first half of 2005. In 2009, we plan to invest $0.7 million for capital workover and facilities in the Buffalo Red River units.

Bakken Field

We control one of the largest acreage positions in the Bakken field of Montana and North Dakota with approximately 1,155,000 gross (581,000 net) acres as of December 31, 2008. Approximately 17% of the net acreage is producing and 83% of the net acreage is undeveloped as of December 31, 2008. Our properties within the Bakken field in Montana and North Dakota represented 35% of our PV-10 in the Rocky Mountain region as of December 31, 2008 and 39% of our average daily Rocky Mountain region Boe production for the three months ended December 31, 2008. As of December 31, 2008 we had completed 308 gross (148.5 net) wells in the Bakken field.

The Bakken formation or Bakken Shale , as it is often called, is one of the most actively drilled unconventional oil resource plays in the United States with approximately 83 rigs drilling in the play as of December 31, 2008, including 76 in North Dakota and seven in Montana. A report issued by the United States Geologic Survey (USGS) in April 2008 estimates that the Bakken Shale contains up to 4.3 billion barrels of recoverable oil using today s technology and classifies it as the largest continuous oil accumulation ever assessed by the USGS.

The Bakken formation is a Devonian-age shale found within the Williston Basin underlying portions of North Dakota and Montana that contains three lithologic members including the upper shale, middle member and lower shale that combined range up to 130 feet thick. The upper and lower shales are highly organic, thermally mature and over pressured and act as both a source and reservoir for the oil. The middle member, which varies in composition from a silty dolomite to shalely limestone or sand, also serves as a reservoir and is thought to be a critical component for commercial production. The Three Forks/Sanish formation found immediately under the Lower Bakken Shale has also proven to contain productive reservoir rock that may add incremental reserves to the play. The Three Forks/Sanish typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as the Sanish sand. All of these reservoir rocks have low porosity and permeability and depend on natural fracturing and artificial fracture stimulation to produce economically. Horizontal drilling and multi-stage fracture stimulation technology has enabled commercial production from this historically non-commercial reservoir. Generally, the Bakken formation is found at vertical depths of 9,000 to 10,500 feet and drilled horizontally on 320, 640 or 1,280-acre spacing with single, dual or triple leg horizontal laterals extending 4,500 to 9,000 feet into the formation. These wells are fracture stimulated to maximize recovery and economic returns. The fracture stimulation techniques vary but most commonly utilize multi-stage mechanically diverted stimulations using un-cemented liners and packers.

Table of Contents

Montana Bakken. Our Montana Bakken production is located in the Elm Coulee field in Richland County, Montana. The Elm Coulee field is listed by the Energy Information Administration as the 16th largest onshore, lower 48 field in the United States ranked by liquid proved reserves. Since drilling our first well in August 2003, we have completed a total of 156 gross (100.2 net) wells in the field as of December 31, 2008. Our daily average production from these wells was approximately 5,727 net Bbls of oil and 3,944 net Mcf of natural gas during the month of December 2008. The field has been developed exclusively with horizontal drilling and has been substantially drilled on 640-acre spacing. During 2008, we began to further develop our acreage in the field on 320 acre spacing and have identified 57 undrilled 320 acre infield locations on our acreage as of December 31, 2008. Out of the 22 gross (16.2 net) wells we drilled in the field during 2008, 12 gross (10.3 net) were 320 acre infield wells. These wells are performing in line with our expected reserve model of 279 MBoe per well.

In December 2008 we also began operations on a one well secondary recovery pilot project to evaluate the potential to increase oil recovery from the Bakken reservoir utilizing CO2 injection. Laboratory tests indicate this technique is feasible and could increase oil recovery from the Bakken reservoir. Using a technique known as the huff and puff method, we began injecting CO2 in January 2009 and expect to complete the injection phase by March 2009. After allowing the CO2 to soak into the reservoir for approximately 30 days, we will flow the CO2 and associated fluids back from the well. Production from the well will be measured and the performance will be analyzed to assess the incremental recovery and economics of the technique.

As of December 31, 2008, we held 131,422 gross (101,010 net) undeveloped acres in the Montana Bakken play within and adjacent to the Elm Coulee field. We have recently suspended drilling in the Montana Bakken due to weakness in oil and natural gas prices and will resume drilling as prices improve.

North Dakota Bakken. Our 2008 drilling program significantly expanded the proven extents of our North Dakota Bakken acreage along the Nesson anticline. During the year we completed 98 gross (27.2 net) wells and exited 2008 producing at an average daily rate of 5,081net Bbls of oil during the month of December 31, 2008, a 276% increase over the same period in 2007 and 1,744 net Mcf of natural gas during the month of December 2008, an increase of 113% over the same period in 2007.

During the year we drilled almost exclusively 1,280-acre spaced, long single leg laterals, up to 9,000 feet long and fracture stimulated these wells with up to 14 mechanically diverted stages using un-cemented liners and packers. We found this technique provided better wellbore integrity and on average delivered higher initial flow rates. Of significance, we completed 27 gross (10.3 net) Three Forks/Sanish wells during 2008. The Three Forks/Sanish formation which lies immediately below the lower Bakken shale is known to be productive locally throughout the Williston Basin and may add incremental reserves to the Bakken play. Our Three Forks/Sanish completions were strategically located throughout our acreage along the Nesson anticline over a distance of approximately 100 miles north to south. The success of these Three Forks/Sanish wells demonstrates the widespread productive potential of the Three Forks/Sanish reservoir underlying our acreage. Although the results in themselves do not demonstrate the Three Forks/Sanish formation adds incremental reserves to the Bakken play, it is notable that the 20 gross (8.9 net) Three Forks/Sanish completions we operated in 2008 had an average initial production rate of 640 gross Boe per day which is 17% higher than our average operated Middle Bakken completion in 2008.

As of December 31, 2008, we held 865,000 gross (378,000 net) undeveloped acres in the North Dakota Bakken field. As of February 23, 2009, we had 10 rigs drilling in the North Dakota Bakken field, including 4 operated by Continental Resources, Inc, and 6 operated by ConocoPhillips through a joint-venture. We plan to invest $71 million drilling 86 gross (20.2 net) wells in the North Dakota Bakken field during 2009.

Table of Contents

Big Horn Basin and Other Rockies

Our wells within the Big Horn Basin in northern Wyoming and other areas within the Rocky Mountain region represented 5% of our PV-10 in the Rocky Mountain Region as of December 31, 2008 and 9% of our average daily Rocky Mountain Region Boe production for the three months ended December 31, 2008. During the three months ended December 31, 2008, we produced an average of 1,794 net Bbls of oil and 4,280 net Mcf of natural gas per day from our wells in the Big Horn Basin and other areas within the Rocky Mountain region.

Our principal property in the Big Horn Basin, the Worland field, produces primarily from the Phosphoria formation. We also have several other ongoing projects in the Rockies including conventional 3D defined Red River and Lodgepole structures in North Dakota and Montana, horizontal Fryburg opportunities in North Dakota and the Lewis Shale and Fort Union in Wyoming.

Conventional Red River. The Red River is a well known conventional producing oil and gas reservoir throughout the Williston Basin of North Dakota and Montana. The production can be quite prolific with individual Red River wells producing up to 1.5 million barrels of oil but the productive reservoir is generally confined to structural closures and structural-stratigraphic traps of 320 acres to 640 acres in size. The potential exists to find this type of conventional Red River production underlying any portion of our Bakken acreage in North Dakota and Montana. To identify these Red River traps generally requires 3D seismic. We own or have under license 964 square miles of 3D seismic over portions of our acreage in Montana and North Dakota. As of December 31, 2008 we had interpreted approximately 8% of this data using our proprietary processing techniques and have identified 9 undrilled potential locations. In 2008, we drilled and completed 6 gross (3.1 net) vertical Red River wells with 4 gross (2.2 net) wells completed as producers for a 71% success rate. During 2009, we plan to continue re-processing and evaluating our 3D seismic to identify new potential drilling locations.

Mid-Continent and Gulf Coast Region

Our properties in the Mid-Continent and Gulf Coast region represented 24% of our PV-10 as of December 31, 2008. During the three months ended December 31, 2008, our average daily production from such properties was 2,321 net Bbls of oil and 37,922 net Mcf of natural gas. Our principal producing properties in this region are located in the Anadarko and Arkoma Basins of Oklahoma, the Michigan Basin and the Illinois Basin.

Arkoma Woodford

The Arkoma Woodford play in Atoka, Coal, Hughes and Pittsburg Counties, Oklahoma has matured into one of the more active unconventional gas resource plays in the United States with 36 rigs drilling in the play industry wide as of December 31, 2008. We owned approximately 161,000 gross (47,000 net) acres in the Woodford play as of December 31, 2008. Since drilling our first well in February, 2006, we have completed a total of 259 gross (41.4 net) horizontal Woodford wells through December 31, 2008. These Arkoma Woodford wells represent 52% of the PV-10 in the Mid-Continent Region as of December 31, 2008 and 41% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2008. During 2008, production from our Arkoma Woodford wells grew 213% from an average of 8,428 Mcf of natural gas equivalent per day during December 2007 to 26,380 Mcf of natural gas equivalent per day in December 2008.

We completed 115 gross (23.3 net) Woodford wells during 2008. This drilling consisted of a combination of exploratory, step-out and development drilling designed to secure acreage and delineate areas of economic production for further development. Of significance, we expanded the known extents of commercial production to the western extents of our Ashland AMI and south into our Big Mac Prospect. We also completed our first well in the East McAlester area. As of December 31, 2008, approximately 72% of our net acreage remained undeveloped.

During the year ended December 31, 2008, we began to develop the field on various densities including 320, 160 and 80-acre spacing, to determine the optimum spacing for development. Results indicated that 80-acre development is economically feasible on much of our acreage. We also began simul-fracing wells when possible to more effectively stimulate and produce the Woodford shale while causing minimal disruption to existing production. We also reduced our average cost per lateral foot drilled by 20% compared to 2007 through improved mud systems, bit selections and operational efficiencies. We also successfully demonstrated that we can drill and complete wells across faults that previously limited the length of lateral drilled. To guide our drilling we acquired 49 square miles of 3-D seismic data during the year bringing the total of 3D seismic we own or have under license to 93 square miles.

We plan to invest approximately $56.0 million drilling 63 gross (8.0 net) horizontal wells in the Arkoma Woodford during 2009. We currently have one operated rig drilling in the play and are in the process of acquiring 53 square miles of 3-D seismic to guide future drilling on our East McAlester acreage.

Anadarko Basin

Our properties within the Anadarko Basin represented 27% of our PV-10 in the Mid-Continent Region as of December 31, 2008 and 40% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2008. Our wells within the Anadarko Basin produce from a variety of sands and carbonates in both stratigraphic and structural traps. During the year we drilled 19 gross (11.5 net) wells with a 90% gross (84% net) success rate. In 2009, we plan to invest approximately $23.0 million in the drilling of 18 gross (5.0 net) wells in the Anadarko Basin.

Anadarko Woodford. We owned 189,246 gross (117,665 net) acres in the emerging Anadarko Woodford shale play of western Oklahoma as of December 31, 2008. This includes 144,000 gross (93,000 net) undeveloped acres acquired in 2008 and 44,923 gross (24,586 net) acres held by production. Our acreage is strategically positioned within the window of thermal maturation for natural gas along the eastern flank of the Anadarko basin extending across portions of Grady, Canadian, Blaine, Custer and Dewey Counties of Oklahoma. The Woodford shale underlying this acreage ranges from 75 to 250 feet thick and occurs at depth ranging from 10,000 to 15,000 feet. Industry peers began drilling and completing horizontal Woodford shale wells in Canadian County, Oklahoma in August of 2007 and as of December 31, 2008 there were 17 rigs drilling in the play. Results announced by various operators in the play have been encouraging, with initial daily production rates of up to 8,300 Mcf of natural gas equivalent per well. Based on our economic model, we expect to recover approximately 5 Bcf to 7 Bcf per well. During 2008 we drilled 2 gross (1.9 net) horizontal Woodford wells and both are currently in the process of being completed.

Anadarko Atoka. We owned 44,938 gross (27,566 net) acres in the emerging Anadarko Atoka Shale play of Western Oklahoma and the Panhandle of Texas as of December 31, 2008. Our acreage is focused in Ellis County, Oklahoma and Lipscomb County, Texas and strategically located along trend with the development of the Novi Lime formation. The Novi Lime formation is important as it serves as both reservoir and drilling conduit for the horizontal wellbore through which the surrounding natural gas charged Atoka shales can be fracture stimulated and produced. The Atoka shales range from 75 feet to 125 feet thick and are present throughout our properties. Public records show as of February 23, 2009, 37 horizontal Atoka wells have been completed by industry peers with initial production rates of up to 7,500 Mcf of natural gas per day. During 2008, we drilled 2 gross (2 net) horizontal Atoka wells. The first well, the Shrewder 1-22H (100% WI) completed flowing 1,297 Mcf of natural gas per day from a short, 1,300 foot, horizontal lateral. The second well, the Jones Trust 1-168H (100% WI) was recently fracture stimulated and currently flow testing at a rate of approximately 700 Mcf of natural gas per day.

Illinois Basin

Our properties within the Illinois Basin represented 20.6% of the PV-10 in the Mid-Continent Region as of December 31, 2008 and 4.9% of our average daily Mid-Continent Region Boe production for the three months ended December 31, 2008. We drilled 19 gross (17 net) wells during 2008 developing fields and expanding our reserve base in the Illinois Basin. Our production within the Illinois Basin is primarily crude oil from units comprised of shallow sand formations under water injection.

Michigan Trenton-Black River

Our Trenton-Black River project in and around Hillsdale County, Michigan continues to produce excellent results guided by our proprietary 3-D seismic techniques. As of December 31, 2008, we had completed 7 gross (5.8 net) operated wells in the play with 6 gross (4.9 net) of the wells completed as Trenton-Black River producers and 1 gross (1 net) well temporarily abandoned. These 6 producing wells were assigned average estimated recoverable reserves of 490 MBoe per well. Combined, these wells were producing an average of 550 gross barrels of oil per day during the month of December 31, 2008. Three of the wells are capable of flowing in excess of the 200 barrels of oil per day allowable set by the Michigan Department of Environmental Quality and 3 are restricted by natural gas flaring restrictions which will be removed once the wells are connected to a natural gas pipeline. A natural gas gathering pipeline has been installed and processing facilities are under construction to enable these flare restricted wells to produce up to the 200 barrels of oil per day allowable rate.

We owned approximately 65,418 gross (52,110 net) acres in the play and have shot, processed and interpreted approximately 40 square mile of 3-D seismic on the acreage as of December 31, 2008. During 2008, we completed the acquisition of 20 square miles of 3-D seismic on our Chicago/Norad project. Interpretation of the seismic data identified up to 14 potential drilling locations. Four of these locations have been selected and permitted for drilling. We plan to acquire another 6.5 square miles of additional 3D seismic data during 2009.

Gulf Coast

During the three months ended December 31, 2008, our average daily production from our Gulf Coast properties was 225 net Bbls of oil and 2,341 net Mcf of natural gas. Our principal producing properties in this region are located in South Texas and Louisiana.

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, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Net production volumes:			
Oil (MBbls)(1)	9,147	8,699	7,480
Natural gas (MMcf)	17,151	11,534	9,225
Oil equivalents (MBoe)	12,006	10,621	9,018
Average prices(1):			
Oil ($/Bbl)	$ 88.87	$ 63.55	$ 55.30
Natural gas ($/Mcf)	6.90	5.87	6.08
Oil equivalents ($/Boe)	77.66	58.31	52.09
Costs and expenses(1):			
Production expense ($/Boe)	$ 8.40	$ 7.35	$ 6.99
Production tax ($/Boe)	4.84	3.13	2.48
General and administrative expense ($/Boe)	2.95	3.15	3.45
DD&A expense ($/Boe)	12.30	9.00	7.27

Table of Contents

(1) Oil sales volumes were 97 MBbls more than production volumes for the year ended December 31, 2008 due to the sale of temporarily stored barrels. Oil sales volumes were 221 MBbls and 21 MBbls less than oil production volumes for the years ended December 31, 2007 and 2006, respectively, due to temporary storage and pipeline line fill. Average prices and per unit costs have been calculated using sales volumes.

The following table sets forth information regarding our average daily production during the fourth quarter of 2008:

	Fourth Quarter 2008		
	Oil (Bbls)	Gas (Mcf)	Total (Boe)
Rockies:			
Red River units	12,860	7,187	14,058
Bakken field			
Montana Bakken	5,697	4,278	6,410
North Dakota Bakken	4,185	1,296	4,401
Other	1,794	4,280	2,507
Mid-Continent:			
Arkoma Woodford	50	19,353	3,276
Other	2,046	16,228	4,751
Gulf Coast	225	2,341	615
Total	26,857	54,963	36,018

Productive Wells

The following table presents the total gross and net productive wells by region and by oil or gas completion as of December 31, 2008:

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Rockies:						
Red River units	265	240	2	2	267	242
Bakken field						
Montana Bakken	151	98	3	2	154	100
North Dakota Bakken	144	46	5	1	149	47
Other	305	271	6	2	311	273
Mid-Continent:						
Arkoma Woodford			259	41	259	41
Other	777	622	243	131	1,020	753
Gulf Coast	5	4	27	13	32	17
Total	1,647	1,281	545	192	2,192	1,473

Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells. As of December 31, 2008, we owned interests in no wells containing multiple completions.

Title to Properties

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

Marketing and Major Customers

We primarily sell our oil production to end users at major market centers. Other production is sold to select midstream marketing companies or oil refining companies at the lease. We have significant production directly connected to a pipeline gathering system, although the balance of our production is transported by truck. Where the oil that is directly marketed is transported by truck, the oil is delivered to the most practical point on a pipeline system for delivery to a sales point downstream on another connecting pipeline. Oil that is sold at the lease is delivered directly onto the purchasers truck and the sale is complete at that point.

During the fourth quarter of 2007 and various periods in 2008, we were unable to market some of our Rocky Mountain area crude at a price acceptable to us. This resulted in increases in our crude oil inventory at various times throughout the year. The prices we were offered were adversely affected by seasonal demand and by pipeline constraints. At various times during 2007 and 2008, we shipped some of our Rocky Mountain crude by railcar to help alleviate this situation and obtain more favorable prices. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, see Risk factors Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

For the year ended December 31, 2008, oil sales to Marathon Oil Company accounted for 44% of our total revenue. No other purchasers accounted for more than 10% of our total oil and gas sales. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil purchasers in our producing regions.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, shortages or the high cost of drilling rigs could delay or adversely affect our development and exploration operations. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

Table of Contents

Regulation of the Oil and Natural Gas Industry

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorating provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders to implement its open access policies. As a result, the interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission (CFTC). See below the discussion of Other Federal Laws and Regulations Affecting Our Industry Energy Policy Act of 2005. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order 704, some of our operations may be required to annually report to FERC, starting May 1, 2009, information regarding natural gas sale transactions depending on the volume of natural gas transacted during the prior calendar year. See below the discussion of Other Federal Laws and Regulations Affecting Our Industry FERC Market Transparency Rules.

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

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 (EP Act 2005). The EP Act 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EP Act 2005 amends the NGA to add an anti- market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act 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 increases the FERC s civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of EP Act 2005, and subsequently denied rehearing. The rules make it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of 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 gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC s NGA enforcement authority.

FERC Market Transparency Rules. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order 704). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu 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, are now required to report, on May 1 of each year beginning in 2009, 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. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires mark