UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

OR

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

Commission file number: 1-34776

Oasis Petroleum Inc.

(Exact name of registrant as specified in its charter)

Delaware	**80-0554627**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1001 Fannin Street, Suite 1500
Houston, Texas **77002**
(Address of principal executive offices) **(Zip Code)**
(281) 404-9500

(Registrant s telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, par value $0.01 per share	**New York Stock Exchange**
(Title of Class)	*(Name of 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 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

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 price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter: $2,743,310,528

Number of shares of registrant s common stock outstanding as of February 23, 2012: 92,747,596

Documents Incorporated By Reference:

Portions of the registrant s definitive proxy statement for its 2012 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2011, are incorporated by reference into Part III of this report for the year ended December 31, 2011.

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OASIS PETROLEUM INC.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2011

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and 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 Annual Report on Form 10-K, 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 Annual Report on Form 10-K, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potential, project and similar expressions are intended to identify statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about:

- our business strategy;
- estimated future net reserves and present value thereof;
- technology;
- cash flows and liquidity;
- our financial strategy, budget, projections, execution of business plan and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating a services company;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- property acquisitions;

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

drilling and completion of wells;

infrastructure for salt water disposal;

gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and domestically;

general economic conditions;

operating environment, including inclement weather conditions;

competition in the oil and natural gas industry;

effectiveness of risk management activities;

environmental liabilities;

counterparty credit risk;

governmental regulation and the taxation of the oil and natural gas industry;

developments in oil-producing and natural gas-producing countries;

uncertainty regarding future operating results; and

plans, objectives, expectations and intentions contained in this report that are not historical.

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All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by Securities law, and 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 Annual Report on Form 10-K 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 Operations and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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PART I

Item 1. Business

Overview

Oasis Petroleum Inc. (together with our consolidated subsidiaries, the Company, we, us, or our) is an independent exploration and productio company focused on the acquisition and development of unconventional oil and natural gas resources in the Montana and North Dakota regions of the Williston Basin. As of December 31, 2011, we have accumulated 307,430 net leasehold acres in the Williston Basin. We are currently exploiting significant resource potential from the Bakken and Three Forks formations, which are present across a substantial portion of our acreage. We believe the location, size and concentration of our acreage in our core project areas create an opportunity for us to achieve cost, recovery and production efficiencies through the large-scale development of our project inventory. Our management team has a proven track record in identifying, acquiring and executing large, repeatable development drilling programs, which we refer to as resource conversion opportunities, and has substantial Williston Basin experience. In 2011, we completed and placed on production 63 gross operated wells in the Williston Basin and achieved 100% success in the finding of hydrocarbons (all of which are economic based on current prices as of December 31, 2011) through the application of the latest drilling and completion techniques. We have built our Williston Basin leasehold acreage position primarily through acquisitions in our three primary project areas: West Williston, East Nesson and Sanish.

DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 78.7 MMBoe as of December 31, 2011, 46% of which were classified as proved developed and 88% of which were comprised of oil. The following table presents summary data for each of our primary project areas as of December 31, 2011:

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
			2012 Budget		Estimated net proved reserves as of December 31, 2011		2011 Average daily production
	Net acreage	Gross wells	Net wells	Drilling capital (In millions)	MMBoe	% Developed	(Boe/d)
Williston Basin							
West Williston	201,265	93	58.0	$ 578	51.6	46	6,639
East Nesson	97,756	39	17.9	151	21.1	35	2,404
Sanish	8,409	60	4.1	29	6.0	75	1,592
Total Williston Basin	307,430	192	80.0	758	78.7	46	10,635
Other							89
Total	307,430	192	80.0	$ 758	78.7	46	10,724

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Our history

Oasis Petroleum Inc. was incorporated in February 2010 pursuant to the laws of the State of Delaware to become a holding company for Oasis Petroleum LLC, which was formed as a Delaware limited liability company in February 2007 by certain members of our senior management team and certain private equity funds managed by EnCap Investments L.P. (EnCap). We completed our initial public offering in June 2010 (IPO). In connection with our IPO and related corporate reorganization, we acquired all of the outstanding membership interests in Oasis Petroleum LLC, our predecessor, in exchange for shares of our common stock. Our assets, which consist of proved and unproved oil and natural gas properties, are owned by Oasis Petroleum North America (OPNA). In June 2011, we formed Oasis Well Services LLC (OWS) to provide well services to OPNA, and in July 2011, we formed Oasis Petroleum Marketing LLC (OPM) to provide marketing services to OPNA.

We built our Williston Basin leasehold acreage position in our West Williston, East Nesson and Sanish project areas through the following acquisitions and development activities:

- In June 2007, we acquired approximately 175,000 net leasehold acres in the Williston Basin with then-current net production of approximately 1,000 Boe/d primarily from conventional formations. This acreage is the core of our West Williston project area.

- In May 2008, we entered into a farm-in and purchase arrangement, under which we earned or acquired approximately 48,000 net leasehold acres, which established our initial position in the East Nesson project area.

- In June 2009, we acquired approximately 37,000 net leasehold acres with then-current net production of approximately 800 Boe/d, of which approximately 92% was from the Williston Basin. This acquisition consolidated our acreage in the East Nesson project area and established our Sanish project area.

- In September 2009, we acquired an additional 46,000 net leasehold acres with then-current net production of approximately 300 Boe/d. This acquisition further consolidated our acreage in the East Nesson project area.

- In the fourth quarter of 2010, we acquired approximately 16,700 net leasehold acres located in Roosevelt County, Montana with then-current net production of approximately 300 Boe/d and approximately 10,000 net leasehold acres primarily located in Richland County, Montana with then-current net production of approximately 200 Boe/d. This acreage is now part of our West Williston project area.

Our business strategy

Our goal is to enhance value by investing capital to build reserves, production and cash flows at attractive rates of return through the following strategies:

- ***Develop our Williston Basin leasehold position.*** We intend to continue to drill and develop our acreage position to maximize the value of our resource potential. During 2011, we completed and brought on production 63 gross (49.2 net) operated Bakken and Three Forks wells in the Williston Basin. As of December 31, 2011, we had 25 gross (19.6 net) operated wells waiting on completion and 7 gross (4.8 net) operated wells drilling in the Bakken and Three Forks formations. Our 2012 drilling plan contemplates drilling approximately 108 gross (74.0 net) operated wells in these project areas. We believe we have the ability to increase or decrease the number of wells drilled during 2012 based on market conditions and program results.

- ***Focus on operational and cost efficiencies.*** Our management team is focused on continuous improvement of our operations and has significant experience in successfully converting early-stage resource conversion opportunities into cost-efficient development projects. We believe the magnitude and concentration of our acreage within our project areas provide us with the opportunity to capture economies of scale, including the ability to drill multiple wells from a single drilling pad, utilizing centralized production and oil, gas and water fluid handling facilities and reducing the time and cost of rig mobilization.

Adopt and employ leading drilling and completion techniques. Our team is focused on enhancing our drilling and completion techniques to maximize overall well economics. We believe these techniques have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of techniques such as drilling longer laterals and more tightly spacing fracturing stimulation stages. We continuously evaluate our internal drilling and completion results and monitor the results of other operators to improve our operating practices. This continued evolution may enhance our initial production rates, ultimate recovery factors and rate of return on invested capital.

Pursue strategic acquisitions with significant resource potential. As opportunities arise, we intend to identify and acquire additional acreage and producing assets in the Williston Basin to supplement our existing operations. Going forward, we may selectively target additional basins that would allow us to employ our resource conversion strategy on large undeveloped acreage positions similar to what we have accumulated in the Williston Basin.

Maintain financial flexibility and conservative financial position. We are committed to maintaining a conservative financial strategy by managing our liquidity position and leverage levels. As of December 31, 2011, we had no outstanding borrowings under our revolving credit facility, no outstanding letters of credit issued under our revolving credit facility, and $840.9 million of liquidity available, including $490.9 million in cash and short-term investments and $350.0 million available under our revolving credit facility. This liquidity position, along with internally generated cash flows, will provide additional financial flexibility as we continue to develop our acreage position in the Williston Basin. We now have access to the public equity and debt markets, and we intend to maintain a conservative, balanced capital structure by prudently raising proceeds from future offerings as additional capital needs arise.

Our competitive strengths

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

Substantial leasehold position in one of North America s leading unconventional oil-resource plays. As of December 31, 2011, our 307,430 net leasehold acres in the Williston Basin was highly prospective in the Bakken formation and 88% of our 78.7 MMBoe net proved reserves in this area were comprised of oil. We believe our acreage is one of the largest concentrated leasehold positions that is prospective in the Bakken formation, and much of our acreage is in areas of significant drilling activity by other exploration and production companies. While our current drilling plans primarily target the Bakken formation, we are also actively drilling and evaluating what we believe to be significant prospectivity in the Three Forks formation that underlies a large portion of our acreage. We expect that the scale and concentration of our acreage will enable us to improve our drilling and completion costs and operational efficiency as we begin infill drilling in 2012 and move to full development mode in 2013.

Large, multi-year project inventory. We believe we have a large inventory of potential drilling locations that we have not yet drilled, a majority of which is operated by us. We plan to drill 108 gross (74.0 net) operated wells in the Williston Basin in 2012.

Management team with proven operating and acquisition skills. Our senior management team has extensive expertise in the oil and gas industry. Our senior technical team has an average of more than 25 years of industry experience, including experience in multiple North American resource plays as well as experience in international basins. We believe our management and technical team is one of our principal competitive strengths relative to our industry peers due to our team s proven track record in identification, acquisition and execution of resource conversion opportunities. In addition, our technical team possesses substantial expertise in horizontal drilling techniques and managing and acquiring large development programs and also has prior experience in the Williston Basin.

Incentivized management team. As of December 31, 2011, our executive officers owned approximately 9% of our common stock. We believe our executive officers ownership interest in us provides them with significant incentives to grow the value of our business for the benefit of all stakeholders.

Operating control over the majority of our portfolio. In order to maintain better control over our asset portfolio, we have established a leasehold position comprised primarily of properties that we expect to operate. We expect to operate approximately 57% of our gross drilling locations, or 90% of our net drilling locations. As of December 31, 2011, over 90% of our total proved reserves were attributable to properties that we expect to operate. Approximately 95% of our estimated 2012 drilling and completion capital expenditure budget is related to operated wells,

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which we anticipate will result in an increase in 2012 of the percentage of our proved reserves attributable to properties we expect to operate. As of December 31, 2011, our average working interest in our operated and non-operated identified drilling locations was 69% and 10%, respectively. Controlling operations will allow us to dictate the pace of development as well as the costs, type and timing of exploration and development activities. We believe that maintaining operational control over the majority of our acreage will allow us to better pursue our strategies of enhancing returns through operational and cost efficiencies and maximizing hydrocarbon recovery through continuous improvement of drilling and completion techniques. We are also better able to control infrastructure investment to drive down operating costs and increase gas production and oil price realizations.

Our operations

Estimated proved reserves

The table below summarizes our estimated proved reserves and related PV-10 at December 31, 2011 and 2010 for each of our project areas based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers. In preparing its reports, DeGolyer and MacNaughton evaluated properties representing all of our PV-10 at December 31, 2011 and 2010 in accordance with the rules and regulations of the Securities and Exchange Commission (SEC) applicable to companies involved in oil and natural gas producing activities. Our proved reserve estimates do not include probable or possible reserves. For the years shown herein and for future periods, our estimated proved reserves were and will be determined using the preceding twelve months unweighted arithmetic average of the first-day-of-the-month prices. The information in the following table does not give any effect to or reflect our commodity derivatives. For a definition of proved reserves under the SEC rules, please see the Glossary of oil and natural gas terms included at the end of this report. For more information regarding our independent reserve engineers, please see Independent petroleum engineers below.

	September 30, At December 31, 2011	September 30,	September 30, At December 31, 2010	September 30,
Project area	**Proved reserves (MMBoe)**	**PV-10(2) (in millions)**	**Proved reserves (MMBoe)**	**PV-10(2) (in millions)**
Williston Basin:				
West Williston	51.6	$ 1,242.6	22.9	$ 380.0
East Nesson	21.1	479.1	9.6	160.7
Sanish	6.0	182.0	7.2	156.4
Total Williston Basin	78.7	1,903.7	39.7	697.1
Other(1)			0.1	0.7
Total	78.7	$ 1,903.7	39.8	$ 697.8

(1) Represents data relating to our properties in the Barnett shale, which we sold in November 2011.

(2) 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 effect of income taxes on discounted future net cash flows. Neither PV-10 nor Standardized Measure represent an estimate of the fair market value of our oil and natural gas properties. The oil and gas industry uses 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. See Reconciliation of PV-10 to Standardized Measure below.

Estimated proved reserves at December 31, 2011 were 78.7 MMBoe, a 98% increase from estimated proved reserves of 39.8 MMBoe at December 31, 2010. Our 2011 estimated proved reserves increased 38.9 MMBoe over our 2010 estimated proved reserves due to our drilling program and higher oil price assumptions at December 31, 2011. Our commodity price assumption for oil increased $16.83/Bbl to $96.23/Bbl for the year ended December 31, 2011 from $79.40/Bbl for the year ended December 31, 2010. Our proved developed reserves increased 18.8 MMBoe, or 111%, to 35.8 MMBoe for the year ended December 31, 2011 from 17.0 MMBoe for the year ended December 31, 2010, primarily due to our drilling program completing 63 gross (49.2 net) operated wells. Our proved undeveloped reserves increased to 42.9 MMBoe for the year ended December 31, 2011 from 22.8 MMBoe for the year ended December 31, 2010 due to our drilling program, significant regional drilling activity, higher commodity price assumptions and higher overall estimated ultimate recoveries using recent drilling and completion techniques.

Estimated proved reserves at December 31, 2010 were 39.8 MMBoe, a 199% increase from estimated proved reserves of 13.3 MMBoe at December 31, 2009. Our 2010 estimated proved reserves increased 26.5 MMBoe over our 2009 estimated proved reserves due to acquisitions, our drilling program and higher oil price assumptions at December 31, 2010. Our commodity price assumption for oil increased $18.36/Bbl to $79.40/Bbl for the year ended December 31, 2010 from $61.04/Bbl for the year ended December 31, 2009. Our proved developed producing reserves increased 11.4 MMBoe, or 204%, to 17.0 MMBoe for the year ended December 31, 2010 from 5.6 MMBoe for the year ended December 31, 2009 due to acquisitions and our drilling program. Our proved undeveloped reserves increased to 22.8 MMBoe for the year ended December 31, 2010 from 7.7 MMBoe for the year ended December 31, 2009 due to our drilling program, significant regional drilling activity, higher commodity price assumptions and higher overall estimated ultimate recoveries using the latest drilling and completion techniques.

The following table sets forth more information regarding our estimated proved reserves at December 31, 2011, 2010 and 2009:

	September 30, 2011	September 30, At December 31, 2010	September 30, 2009
Reserve Data(1):			
Estimated proved reserves:			
Oil (MMBbls)	69.1	36.6	12.4
Natural gas (Bcf)	57.9	19.4	5.3
Total estimated proved reserves (MMBoe)	78.7	39.8	13.3
Percent oil	88%	92%	93%
Estimated proved developed reserves:			
Oil (MMBbls)	31.8	15.7	5.2
Natural gas (Bcf)	24.5	8.2	2.3
Total estimated proved developed reserves (MMBoe)	35.8	17.0	5.6
Percent proved developed	46%	43%	42%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	37.3	20.9	7.2
Natural gas (Bcf)	33.4	11.2	3.0
Total estimated proved undeveloped reserves (MMBoe)	42.9	22.8	7.7
PV-10 (in millions)(2)	$ 1,903.7	$ 697.8	$ 133.5
Standardized Measure (in millions)(3)	$ 1,319.5	$ 485.7	$ 133.5

(1) Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $96.23/Bbl for oil and $4.12/MMBtu for natural gas, $79.40/Bbl for oil and $4.38/MMBtu for natural gas, and $61.04/Bbl for oil and $3.87/MMBtu for natural gas for the years ended December 31, 2011, 2010, and 2009, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

(2) 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 effect of income taxes on discounted future net cash flows. However, our PV-10 and our Standardized Measure are equivalent at December 31, 2009 because as of December 31, 2009, we were a limited liability company not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes was provided prior to our IPO and corporate reorganization because taxable income passed through to our equity holders. In connection with the closing of our IPO, we merged into a corporation and became subject to federal and state entity-level taxation. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. See Reconciliation of PV-10 to Standardized Measure below.

(3) Standardized Measure represents the present value of estimated future net cash flows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses (if applicable), discounted at 10% per annum to reflect timing of future cash flows.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the

Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

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The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2011, 2010 and 2009:

	September 30, 2011	September 30, December 31, 2010 (In millions)	September 30, 2009
PV-10	$ 1,903.7	$ 697.8	$ 133.5
Present value of future income taxes discounted at 10%(1)	584.2	212.1	
Standardized Measure of discounted future net cash flows	$ 1,319.5	$ 485.7	$ 133.5

(1) Our PV-10 and our Standardized Measure are equivalent at December 31, 2009, because as of December 31, 2009, we were a limited liability company not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes was provided prior to our IPO and corporate reorganization because taxable income passed through to our equity holders. In connection with the closing of our IPO, we merged into a corporation and became subject to federal and state entity-level taxation. See Note 11 to our audited consolidated financial statements.

The PV-10 of our estimated proved reserves at December 31, 2011 was $1,903.7 million, a 173% increase from PV-10 of $697.8 million at December 31, 2010. This increase was due to an increase in reserves and higher oil price assumptions year over year.

Estimated future net revenues

The following table sets forth the estimated future net revenues, excluding derivative contracts, from proved reserves, the present value of those net revenues (PV-10) and the expected benchmark prices used in projecting net revenues at December 31, 2011, 2010 and 2009:

(In millions)	September 30, 2011	September 30, At December 31, 2010	September 30, 2009
Future net revenues	$ 4,034.9	$ 1,561.3	$ 286.1
Present value of future net revenues:			
Before income tax (PV-10)	1,903.7	697.8	133.5
After income tax (Standardized Measure)(1)	1,319.5	485.7	133.5
Benchmark oil price($/Bbl)(2)	$ 96.23	$ 79.40	$ 61.04

(1) Standardized Measure represents the present value of estimated future net cash inflows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses (if applicable), discounted at 10% per annum to reflect timing of future cash flows. Our PV-10 and our Standardized Measure are equivalent at December 31, 2009 because as of December 31, 2009, we were a limited liability company not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes was provided prior to our IPO and corporate reorganization because taxable income passed through to our equity holders. In connection with the closing of our IPO, we merged into a corporation and became subject to federal and state entity-level taxation.

(2) Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The

unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $96.23/Bbl for oil and $4.12/MMBtu for natural gas, $79.40/Bbl for oil and $4.38/MMBtu for natural gas, and $61.04/Bbl for oil and $3.87/MMBtu for natural gas for the years ended December 31, 2011, 2010, and 2009, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2011, 2010 and 2009 are based on costs in effect at December 31 of each year and the 12-month unweighted arithmetic average of the first-day-of-the-month price for January through December of such year, without giving effect to derivative transactions, and are held constant throughout the life of the properties. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

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Proved undeveloped reserves

At December 31, 2011, we had approximately 42.9 MMBoe of proved undeveloped reserves as compared to 22.8 MMBoe at December 31, 2010.

The following table summarizes the changes in our proved undeveloped reserves during 2011 (in MBoe):

	September 30,
At December 31, 2010	22,762
Extensions, discoveries and other additions	30,472
Purchases of minerals in place	39
Sales of minerals in place	
Revisions of previous estimates	1,499
Conversion to proved developed reserves	(11,896)
At December 31, 2011	42,876

During 2011, we spent $220.7 million converting 11,896 MBoe of proved undeveloped reserves to proved developed reserves. During 2010, we spent $41.5 million converting 3,481 MBoe of proved undeveloped reserves to proved developed reserves.

All of our proved undeveloped reserves at December 31, 2011 are expected to be developed within the next five years.

Independent petroleum engineers

Our estimated reserves and related future net revenues, PV-10 and Standardized Measure at December 31, 2011, 2010 and 2009 are based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and current guidelines established by the SEC. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Calgary and Moscow. The firm s more than 100 professionals include engineers, geologists, geophysicists, petrophysicists and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies and equity studies related to the domestic and international energy industry. DeGolyer and MacNaughton has provided such services for over 70 years. The Senior Vice President at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve estimates is a Registered Petroleum Engineer in the State of Texas with more than 35 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974 and he is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas or mineral properties, or securities or notes of clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. The firm is a Texas Registered Engineering Firm.

Technology used to establish proved reserves

In accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities, proved reserves are those quantities of 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. The term reasonable certainty implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, DeGolyer and MacNaughton 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, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques. For wells and locations targeting the Bakken and Three Forks formations, the evaluation included an assessment of the beneficial impact of the use of multi-stage hydraulic fracture stimulation treatments on estimated recoverable reserves. In addition to assessing reservoir continuity, geologic data from well logs, core analyses and seismic data related to the Bakken formation were used to estimate original oil in place. In areas where estimated proved reserves were attributed to more than one well per spacing unit, the estimated original oil in place was used to calculate reasonable estimated recovery factors based on experience with similar reservoirs where similar drilling and completion techniques have been employed.

Internal controls over reserves estimation process

We employ DeGolyer and MacNaughton as the independent reserves evaluator for 100% of our reserves base. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with the independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished for the reserves estimation process. Brett Newton, Senior Vice President of Asset Management, is the technical person primarily responsible for overseeing the reserves evaluation process. He has over 20 years of industry experience with positions of increasing responsibility in engineering and management. He holds both a Bachelor of Science degree and Master of Science degree in petroleum engineering. Mr. Newton reports directly to our Chief Operating Officer.

Throughout each fiscal year, our technical team meets with the independent reserve engineers to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data into our reserves evaluation software as well as management review, such as, but not limited to the following:

- Comparison of historical expenses from the lease operating statements and work-over authorizations for expenditure to the operating costs input in our reserves database;
- Review of working interest and net revenue interest in our reserves database against the Company s well system;
- Review of realized prices and differentials from index prices from the well profitability report to the differentials used in our reserves database;
- Review of updated capital costs prepared by our operations team;
- Review of internal reserve estimates by well and by area by our internal reservoir engineers;
- Discussion of material reserve variances among our internal reservoir engineers and our Senior Vice President of Asset Management;
- Review of a preliminary copy of the reserve report by our Chief Operating Officer with representatives of our independent reserve engineers and internal technical staff; and
- Audit Committee review of our reserves estimation process on an annual basis.

Production, revenues and price history

Oil and natural gas are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand for oil and natural gas in the United States has increased dramatically over the last ten years. However, the economic slowdown during the second half of 2008 and through 2009 reduced this demand. In 2010 and 2011, demand for oil and natural gas increased as the economy recovered. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding oil and natural gas production, revenues, realized prices and production costs for the periods indicated. For additional information on price calculations, please see information set forth in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation.

	September 30,	September 30, Year Ended December 31,	September 30,
	2011	2010	2009
Operating data:			
Net production volumes:			
Oil (MBbls)	3,732	1,792	658
Natural gas (MMcf)	1,092	651	326
Oil equivalents (MBoe)	3,914	1,900	712
Average daily production (Boe/d)	10,724	5,206	1,950
Average sales prices:			
Oil, without realized derivatives (per Bbl)	$ 86.18	$ 69.60	$ 55.32
Oil, with realized derivatives (per Bbl)(1)	85.15	69.53	58.82
Natural gas (per Mcf)(2)	8.02	6.52	4.24
Costs and expenses (per Boe of production):			
Lease operating expenses	$ 8.70	$ 7.67	$ 12.21
Production taxes	8.65	7.25	5.35
Depreciation, depletion and amortization	19.16	19.91	23.42
General and administrative expenses	7.52	10.39	13.12
Stock-based compensation expenses(3)		4.60	

(1) Realized prices include realized gains or losses on cash settlements for our commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes.

(2) Natural gas prices include the value for natural gas and natural gas liquids.

(3) In March 2010, we recorded a $5.2 million stock-based compensation charge associated with OP Management granting 1.0 million C Units to certain of our employees. During the fourth quarter of 2010, we recorded an additional $3.5 million in stock-based compensation expense primarily associated with OP Management granting discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors. See Note 10 to our audited consolidated financial statements.

Net production volumes for the year ended December 31, 2011 were 3,914 MBoe, a 106% increase from net production of 1,900 MBoe for the year ended December 31, 2010. Our net production volumes increased 2,014 MBoe over 2010 due to a successful operated and non-operated drilling and completion program. Average oil sales prices, without realized derivatives, increased by $16.58/Bbl, or 24%, to an average of $86.18/Bbl for the year ended December 31, 2011 as compared to the year ended December 31, 2010. Giving effect to our derivative transactions in both periods, our oil sales prices increased $15.62/Bbl to $85.15/Bbl for the year ended December 31, 2011 from $69.53/Bbl for the year ended December 31, 2010.

Net production volumes for the year ended December 31, 2010 were 1,900 MBoe, a 167% increase from net production of 712 MBoe for the year ended December 31, 2009. Our net production volumes increased 1,188 MBoe over 2009 due to a successful operated and non-operated drilling and completion program and acquisitions. Average oil sales prices, without realized derivatives, increased by $14.28/Bbl, or 26%, to an average of $69.60/Bbl for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Giving effect to our derivative transactions in both periods, our oil sales prices increased $10.71/Bbl to $69.53/Bbl for the year ended December 31, 2010 from $58.82/Bbl for the year ended December 31, 2009.

The following table sets forth information regarding our average daily production for the years ended December 31, 2011 and 2010:

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
			Average daily production for the years ended December 31,			
		2011			2010	
	Bbls	Mcf	Boe	Bbls	Mcf	Boe
Williston Basin:						
West Williston	6,426	1,278	6,639	1,976	564	2,070
East Nesson	2,333	430	2,404	1,607	215	1,643
Sanish	1,467	750	1,592	1,325	561	1,419
Total Williston Basin	10,226	2,458	10,635	4,908	1,340	5,132
Other		533	89		444	74
Total	10,226	2,991	10,724	4,908	1,784	5,206

Productive wells

The following table presents the total gross and net productive wells by project area as of December 31, 2011:

	September 30,	September 30,	September 30,	September 30,
	Total wells		Bakken and Three Forks	
	Gross	Net	Gross	Net
Williston Basin:				
West Williston	216	109.1	109	61.8
East Nesson	91	37.1	91	37.1
Sanish	174	13.1	174	13.1
Total	481	159.3	374	112.0

Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells.

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Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2011 for each of our project areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Developed acres		Undeveloped acres		Total acres	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin:						
West Williston	156,613	103,795	161,201	97,470	317,814	201,265
East Nesson	62,396	39,651	92,556	58,105	154,952	97,756
Sanish	41,320	8,396	560	13	41,880	8,409
Total	260,329	151,842	254,317	155,588	514,646	307,430

We have increased our acreage that is held by production to approximately 184,000 as of December 31, 2011.

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2011 that will expire over the next three years by project area unless production is established within the spacing units covering the acreage prior to the expiration dates:

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
	Expiring 2012		Expiring 2013		Expiring 2014	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin:						
West Williston	35,782	21,652	26,649	11,179	37,350	14,036
East Nesson	26,786	10,240	45,274	23,876	13,952	4,156
Sanish	560	13				
Total	63,128	31,905	71,923	35,055	51,302	18,192

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2011, 2010 and 2009. Gross wells reflect the sum of all wells, operated and non-operated, in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
			Year ended December 31,			
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	128	48.4	100	22.7	31	2.3
Gas			2	0.1		
Dry						
Total development wells	128	48.4	102	22.8	31	2.3

Exploratory wells:						
Oil	9	6.2	14	5.7	12	5.0
Gas						
Dry						
Total exploratory wells	9	6.2	14	5.7	12	5.0
Total wells	137	54.6	116	28.5	43	7.3

As of December 31, 2011, there were 32 gross (24.4 net) operated wells awaiting completion or in the process of drilling.

Our drilling activity has increased each year since our inception. Exploration wells in 2011, 2010 and 2009 primarily focused on delineation and appraisal of the Bakken formation in our West Williston and East Nesson areas. Following our June 2009 acquisition, many operators increased the pace of development drilling in the Sanish project area, and as a result, we participated in a number of wells on a non-operated basis.

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In 2011, we allocated a portion of the costs for a well that was unsuccessful due to mechanical complications in the Three Forks formation to exploratory dry hole expense. The well was successfully plugged back and completed in the Bakken formation. We did not drill any dry hole wells in 2009 or 2010. Consistent with our 2012 capital plan, we expect to continue to focus on drilling in the Bakken and Three Forks formations.

Capital expenditure budget

In 2011, we spent $666.0 million on capital expenditures, which represented an approximate 89% increase over the $352.4 million spent during 2010. This increase was a result of continued improvement of industry conditions and drilling and completion technology in the Bakken formation as well as increased economics in the area and an increase in total net wells drilled in 2011. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources Cash flows used in investing activities.

Our total 2012 capital expenditure budget is $884 million, which includes $846 million for exploration and production (E&P) capital expenditures and $38 million for non-E&P capital expenditures. Our planned capital expenditures primarily consist of:

- $758 million of development capital for operated and non-operated wells (including expected savings from services provided by OWS);
- $57 million for constructing infrastructure to support production in our core project areas, primarily related to salt water disposal systems that will lower lease operating expenses;
- $25 million for maintaining and expanding our leasehold position;
- $6 million for micro-seismic work, purchasing seismic data and other test work;
- $15 million for OWS, including $12 million for equipment budgeted and ordered in 2011 that will arrive in the first quarter 2012; and
- $23 million for other non-E&P capital, including items such as district tools, administrative capital and capitalized interest.

While we have budgeted $884 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling results as the year progresses. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources.

Our core project areas

Williston Basin

Our operations are focused in the North Dakota and Montana areas of the Williston Basin. While we have interests in a substantial number of wells in the Williston Basin that target several different zones, our exploration and development activities are currently concentrated in the Bakken formation. Our management team originally targeted the Williston Basin because of its oil prone nature, multiple, stacked producing horizons, substantial resource potential and management s previous professional history in the basin. The Williston Basin also has established infrastructure and access to materials and services. Regulatory delays are minimal in the Williston Basin due to fee ownership of properties, efficient state and local regulatory bodies and reasonable permitting requirements.

The entire Williston Basin is spread across North Dakota, South Dakota, Montana and parts of southern Canada. The basin produces oil and natural gas from numerous producing horizons including, but not limited to, the Bakken, Three Forks, Madison and Red River formations. Commercial oil production activities began in the Williston Basin in the 1950 s, with the first well drilled in 1953. Since then, an estimated 3.8 billion barrels have been produced from the basin, primarily from conventional oil accumulations, which can be found at depths ranging from 5,000 feet to 15,000 feet. The Williston Basin is

now one of the most actively drilled unconventional oil resource plays in the United States, with approximately 212 rigs drilling in the basin, including 194 in North Dakota and 18 in Montana, based on Anderson Reports weekly rig count dated January 24, 2012. A report issued by the United States Geological Survey in April 2008 classified these formations as the largest continuous oil accumulation ever assessed by it in the contiguous United States.

The Devonian-age Bakken formation is found within the Williston Basin underlying portions of North Dakota and Montana and is comprised of three lithologic members including the upper shale, middle Bakken and lower shale. The formation ranges up to 150 feet thick. The upper and lower shales are highly organic, thermally mature and over pressured and can act as both a source and reservoir for the oil. The middle Bakken, which varies in composition from a silty dolomite to shaley limestone or sand, also serves as a reservoir and is a critical component for commercial production. Generally, the Bakken formation is found at vertical depths of 8,500 to 11,500 feet.

Following the drilling of the first well in 1953, vertical well development of the Bakken formation occurred intermittently until 1987, when development of the upper shale using horizontal wells began to occur in the Bicentennial and Elkhorn Ranch areas. Development in the middle Bakken using horizontal wells began in 2001 with the discovery of the Elm Coulee Field. The use of horizontal drilling and improvements in completion technology has since expanded the development of the middle Bakken across a larger portion of the Williston Basin.

Generally, the reservoir rocks in the Bakken formation exhibit low porosity and permeability and require horizontal drilling and fracture stimulation technology in order to produce economically. The fracture stimulation techniques vary but most commonly utilize multi-stage mechanically diverted stimulations using un-cemented liners and packers. Completion techniques have evolved as the Bakken formation has developed, with operators generally increasing lateral length and fracture stimulation stages. We believe operators also increased estimated ultimate recoveries of hydrocarbons by over 100% across a large portion of the Williston Basin based on our results to date as well as publicly available information for other operators in the basin. Based on our geologic interpretation of the Bakken formation, the evolution of completion techniques, our own drilling results and publicly available drilling results for other operators in the basin, we believe that a substantial portion of our Williston Basin acreage is prospective in the Bakken formation.

The Three Forks formation, generally found immediately under the Bakken formation, has also proven to contain productive reservoir rock that may add incremental reserves to our existing leasehold positions. The Three Forks formation typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as Sanish sand. The Three Forks formation is an unconventional carbonate play. Similar to the Bakken formation, the Three Forks formation has recently been exploited primarily using horizontal drilling and advanced completion techniques. Drilling in the Three Forks formation began in mid-2008 and a number of operators are currently drilling wells targeting this formation. Based on our geologic interpretation of the Three Forks formation and the evolution of completion techniques, we believe that much of our Williston Basin acreage is prospective in the Three Forks formation.

Our total leasehold position in the Williston Basin as of December 31, 2011 consisted of 307,430 net acres. Our estimated net proved reserves in the Williston Basin were 78.7 MMBoe at December 31, 2011. Of our proved reserves in the Williston Basin, approximately 35.8 MMBoe were proved developed reserves, which are comprised of a combination of wells drilled to conventional reservoirs, Bakken wells drilled with completion techniques used in 2008 and 2009 and Bakken and Three Forks wells to be drilled with completion techniques similar to those we currently employ. Based on our results to date, we estimate that the Bakken and Three Forks wells drilled with more recent completion techniques will achieve estimated ultimate recovery rates that will in many cases more than double the ultimate recovery rates we expect from the Bakken wells with older completion techniques. Based on publicly available information for other operators in the basin, we believe this trend towards higher recovery rates is generally consistent across the basin. Of our proved reserves, 42.9 MMBoe were proved undeveloped reserves, all of which consisted of Bakken and Three Forks wells to be drilled with recent completion techniques. We expect that all of our identified drilling locations in each of our project areas will be drilled and completed using completion techniques similar to those we currently employ.

As of December 31, 2011, we had a total of 159.3 net operated and non-operated producing wells and 131.9 net operated producing wells in the Williston Basin. We had average daily production of 10,635 net Boe/d for the year ended December 31, 2011 in the Williston Basin. During 2011, our Bakken and Three Forks wells produced a daily average of 9,938 net Boe/d with 112.0 net producing wells on December 31, 2011. Accordingly, our 112.0 net Bakken and Three Forks wells were responsible for 93% of our average daily production during 2011. Our working interest for all producing wells averages 33% and in the wells we operate is approximately 82%. As of January 1, 2012, we were drilling or completing 55 gross (26.0 net) wells in the Williston Basin. We participated in the drilling and completion of 135 gross wells for the year ended 2011.

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Currently, we estimate our capital expenditures for 2012 will be $884 million, which includes drilling 108 gross (74.0 net) horizontal operated wells, drilling numerous non-operated wells, construction of infrastructure to support production and leasehold acquisitions. Since most of this capital is expected to be spent on horizontal drilling in the Bakken and Three Forks formations, we expect that the proportion of our production from these formations will grow in the future. By using advanced completion techniques and longer laterals, the wells in the Bakken formation in our West Williston and East Nesson project areas, which we have participated in, have generally produced average gross oil rates of between or exceeding 350 to 900 barrels per day for the first 30 days of steady production and are expected to decline to between or exceeding 100 and 200 barrels per day after 12 months of production. We believe that this production profile is comparable to that realized in other areas of the Williston Basin with similar geological characteristics and completion techniques.

Our Williston Basin activities are evaluated in three primary areas of operations: West Williston, East Nesson and Sanish.

West Williston

The West Williston project area was our first area of operations and was established through an asset acquisition from Bill Barrett Corporation in June 2007. We control 201,265 net acres in this area, primarily in Williams and McKenzie counties in North Dakota and Roosevelt and Richland counties in Montana.

We had average daily production of 6,639 net Boe/d for the year ended December 31, 2011, 90% of which was produced from the Bakken and Three Forks formations and the remainder from other conventional formations. As of December 31, 2011, we had an average working interest of over 50% and operated over 90% of our 109.1 net producing wells in the West Williston project area.

During the year ended December 31, 2011, we participated in the drilling and completion of 57 gross (42.3 net) horizontal Bakken and Three Forks wells in the West Williston project area. As of January 1, 2012, we were participating in drilling or completion of 30 gross (20.8 net) wells in the West Williston project area. We have budgeted $577.9 million in capital expenditures in the West Williston project area in 2012 for the drilling and completion of 93 gross (58.0 net) wells.

East Nesson

We expanded into the East Nesson project area through a farm-in transaction in May 2008 with Fidelity Exploration and Production Company and Kerogen Resources, Inc. We subsequently increased our working interests in the area through the acquisitions of assets from Kerogen Resources, Inc. and additional working interests from Fidelity Exploration in June 2009 and September 2009, respectively. We control 97,756 net acres in this area, primarily in Mountrail and Burke counties in North Dakota.

We had average daily production of 2,404 net Boe/d for the year ended December 31, 2011, all of which was produced from the Bakken and Three Forks formations. As of December 31, 2011, we had an average working interest of 40% and operated 88% of our 37.1 net producing wells in the East Nesson project area.

During the year ended December 31, 2011, we drilled and completed 24 gross (7.8 net) horizontal Bakken and Three Forks wells in the East Nesson project area. As of January 1, 2012, we were drilling or completing 6 gross (4.1 net) wells in the East Nesson project area. We have budgeted $151.7 million in capital expenditures in the East Nesson project area in 2012 for the drilling and completion of 39 gross (17.9 net) wells.

Sanish

In June 2009, we expanded into the Sanish project area through the acquisition of assets from Kerogen Resources, Inc. We control 8,409 net acres in this area, all of which are located in Mountrail County in North Dakota.

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We had average daily production of 1,592 net Boe/d for the year ended December 31, 2011, all of which was produced from the Bakken and Three Forks formations. As of December 31, 2011, we had an average working interest of 7% in our 13.1 net wells in the Sanish project area. Our properties in the Sanish project area are entirely operated by other operators, the largest of which are Whiting Petroleum Corporation and Fidelity Exploration.

During the year ended December 31, 2011, we participated in the drilling and completion of 54 gross (3.5 net) horizontal Bakken and Three Forks wells in the Sanish project area. As of January 1, 2012, we were participating in the drilling or completion of 19 gross (1.1 net) wells in the Sanish project area. We have budgeted $28.6 million in capital expenditures in the Sanish project area in 2012 for the drilling and completion of 60 gross (4.1 net) wells.

Other operating areas

Barnett Shale

As part of the Kerogen Resources asset acquisition in June 2009, we acquired approximately 3,000 net acres with then-current net production of approximately 140 Boe/d in the Barnett shale play in Texas. In December 2009, we sold a portion of these wells and acreage, and in November 2011, we sold the remaining portion of these Texas wells and acreage.

Marketing, transportation and major customers

The Williston Basin crude oil transportation and refining infrastructure has grown substantially in recent years, largely in response to drilling activity in the Bakken formation. According to a presentation from the North Dakota Pipeline Authority dated January 24, 2012, there were approximately 415,000 barrels per day of crude oil pipeline transportation capacity in the Williston Basin as of December 31, 2011. In addition, approximately 300,000 barrels per day of specifically dedicated railcar transportation capacity has been placed into service as of December 31, 2011. Based on publicly announced expansion projects, pipeline transportation and refining capacity for Williston Basin oil production could increase by approximately 222,000 barrels per day by the end of 2013. As of December 31, 2011, we sold a substantial majority of our oil production directly at the wellhead and were not responsible for its transportation. However, the price we receive at the wellhead is impacted by transportation and refining infrastructure constraints. In February 2012, the quoted prices for oil coming out of the Williston Basin on pipeline (typically quoted at Clearbrook, Minnesota and Guernsey, Wyoming) (Bakken Crude Oil) was substantially less than prices quoted for WTI due to refinery and transportation constraints. Transportation constraints were largely due to increased volumes produced in North Dakota in the second half of 2011. In December 2011, oil production in North Dakota was approximately 535,000 barrels per day compared to approximately 386,000 barrels per day in June 2011. Oil from Canada also put pressure on the existing pipeline infrastructure that terminates in Midwest refineries. Although there were 300,000 barrels per day of railcar transportation capacity in place as of December 31, 2011, these railcar facilities are not running at nameplate capacity due to limited availability of railcars. We believe the operators of these railcar facilities have railcars on order and expect utilization on these facilities to increase substantially during the first half of 2012. Additionally, during 2012 we expect to begin transporting a portion of our crude oil on gathering systems, originating at the wellhead, in the West Williston, which will reduce the need to transport barrels by truck from the wellhead. The gathering system is expected to provide us access to multiple pipelines and rail outlets where we can sell our crude oil. For a discussion of the potential risks to our business that could result from transportation and refining infrastructure constraints in the Williston Basin, please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

We principally sell our oil and natural gas production to marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is transported by truck to storage facilities. 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, please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production and Risk Factors Risks related to the oil and natural gas industry and our business Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows.

For the year ended December 31, 2011, sales to Texon L.P., Plains All American Pipeline, L.P. and Enserco Energy Inc. accounted for approximately 18%, 16% and 15%, respectively, of our total sales. For the year ended December 31, 2010, sales to Plains All American Pipeline, L.P., Texon L.P. and Whiting Petroleum Corporation accounted for approximately 28%, 19% and 11%, respectively, of our total sales. For the year ended December 31, 2009, sales to Tesoro Refining and Marketing Company and Texon L.P. accounted for approximately 32% and 30%, respectively, of our total sales. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2011, 2010 and 2009. 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 and natural gas purchasers in our producing regions.

As of December 31, 2011, we sold a substantial majority of our oil and condensate directly at the wellhead to a variety of purchasers at prevailing market prices under short-term contracts that normally provide for us to receive a market-based price, which incorporates regional differentials that include, but are not limited to, transportation costs and adjustments for product quality. Crude oil produced and sold in the Williston Basin has historically sold at a discount to the price quoted for NYMEX West Texas Intermediate (WTI) crude oil due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to the production of oil in the area increasing to a point that it temporarily surpasses the available pipeline transportation and refining capacity in the area.

Since most of our oil and natural gas production is sold under market-based or spot market contracts, the revenues generated by our operations are highly dependent upon the prices of and demand for oil and natural gas. The price we receive for our oil and natural gas production depends upon numerous factors beyond our control, including but not limited to seasonality, weather, competition, availability of transportation and gathering capabilities, the condition of the United States economy, foreign imports, political conditions in other oil-producing and natural gas-producing regions, the actions of the Organization of Petroleum Exporting Countries, or OPEC, and domestic government regulation, legislation and policies. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments. Furthermore, a decrease in the price of oil and natural gas could have an adverse effect on the carrying value of our proved reserves and on our revenues, profitability and cash flows. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

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Market, economic, transportation and regulatory factors may in the future materially affect our ability to market our oil or natural gas production. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Competition

The oil and natural gas industry is highly competitive in all phases. We encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of leasing options on oil and natural gas properties to the exploration and development of those properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do. Such companies may be able to pay more for lease options on oil and natural gas properties and exploratory locations and to define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Title to properties

As is customary in the oil and gas industry, we initially conduct a preliminary review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with general industry standards. 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 the 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. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business We may incur losses as a result of title defects in the properties in which we invest.

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt our drilling and producing activities and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

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Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations are frequently amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (FERC) and the courts. We cannot predict when or whether any such proposals may become effective.

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 by common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. Most recently, on December 16, 2010, the FERC established a new price index for the five-year period beginning July 1, 2011.

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 generally governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 (NGA), the Natural Gas Policy Act of 1978 (NGPA) and regulations issued under those statutes. 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 market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, 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, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC s pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

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 under Order No. 637 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) and the Federal Trade Commission (FTC). Please 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 No. 704, some of our operations may be required to annually report to FERC on May 1 of each year for the previous calendar year. Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted. Please see below the discussion of Other federal laws and regulations affecting our industry FERC Market Transparency Rules.

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC s determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes 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 and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. 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.

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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 Energy Policy Act of 2005 (EPAct 2005). EPAct 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, EPAct 2005 amends the NGA to add an anti-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. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1 million 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 million 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-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, 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, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, 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 No. 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC s NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, we could be subject to substantial penalties and fines.

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, or Order No. 704. Under Order No. 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 required 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. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC s policy statement on price reporting.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the FTC issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

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

Environmental and occupational health and safety regulation

Our exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered species; require investigatory and remedial actions to mitigate pollution conditions; impose obligations to reclaim and abandon well sites and pits; and impose specific criteria addressing worker protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in federal or state environmental laws and regulations or re-interpretation of applicable enforcement policies that result in more stringent and costly well construction, drilling, water management or completion activities, or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that we will be able to remain in compliance in the future with such existing or any new laws and regulations or that such future compliance will not have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and wastes

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended (CERCLA), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These classes of persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these responsible persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency (EPA) and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also are subject to the requirements of the Resource Conservation and Recovery Act, as amended (RCRA), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes and nonhazardous solid wastes. Under the authority of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of oil and natural gas from regulation as hazardous wastes, we can provide no assurance that this exemption will be preserved in the future. For instance, in September 2010, the Natural Resources Defense Council filed a petition for rulemaking with the EPA requesting reconsideration of the continued application of this RCRA exclusion but, to date, the EPA has not taken any action on the petition. Repeal or modification of this exclusion or similar exemptions under state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the natural gas and oil industry in general. In any event, these excluded wastes are subject to regulation as nonhazardous solid wastes. In addition, we generate petroleum hydrocarbon wastes and ordinary industrial wastes in the course of our operations that may be regulated as hazardous wastes.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these petroleum hydrocarbons and wastes have been taken for recycling or disposal. In addition, certain of these properties have been operated by the third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Air emissions

The Clean Air Act, as amended, and comparable state laws and regulations restrict the emission of various air pollutants from many sources through air emissions standards, construction and operating permitting programs, and the imposition of other monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, on July 28, 2011, the EPA proposed a range of new regulations that would establish new air emission controls for oil and natural gas production, including, among other things, the application of reduced emission completion techniques, referred to as green completions, for completion of newly drilled and fractured wells in addition to establishing specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. Final action on the proposed rules is expected no later than April 3, 2012. If this action is finalized, we do not believe that such requirements will have a material adverse effect on our operations.

Climate change

Based on findings made by the EPA in December 2009 that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the Earth s atmosphere and other climatic changes, the EPA adopted regulations under existing provisions of the federal Clean Air Act that restrict emissions of GHGs, including one that requires reductions in emissions of GHGs from motor vehicles and another one that requires certain construction and operating permit reviews for GHG emissions from large stationary sources. The EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V permitting programs, pursuant to which these permitting programs have been tailored to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet best available control technology standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas production facilities, which may include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption and implementation of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Water discharges

The Federal Water Pollution Control Act, as amended (the Clean Water Act), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The Oil Pollution Act of 1990, as amended (OPA), which amends the Clean Water Act, establishes strict liability and natural resources damages liability for unauthorized discharges of oil into waters of the United States. The OPA requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Hydraulic fracturing activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from unconventional formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and gas commissions, but the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nevertheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations conducted by third parties and associated legal expenses in accordance with, and subject to, the terms of such policies.

Endangered Species Act considerations

The federal Endangered Species Act, as amended (ESA), may restrict exploration, development and production activities that may affect endangered and threatened species or their habitats. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits the taking of endangered species. Federal agencies are required to insure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to make a determination on a listing of more than 250 species as endangered or threatened under the ESA over the next six years, through the agency s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

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Operations on federal lands

Performance of oil and gas exploration and production activities on federal lands, including Indian lands and lands administered by the federal Bureau of Land Management (BLM) may be subject to the National Environmental Policy Act, as amended (NEPA). NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs, to evaluate major agency actions, such as the issuance of permits that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Depending on any mitigation strategies recommended in such environmental assessments or environmental impact statements, we could incur added costs, which could be substantial.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended (OSHA), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Employees

As of December 31, 2011, we employed 146 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. From time to time we utilize the services of independent contractors to perform various field and other services.

Offices

As of December 31, 2011, we leased 65,992 square feet of office space in Houston, Texas at 1001 Fannin Street, where our principal offices are located. The lease for our Houston office expires in September 2017. We also own a field office in Williston, North Dakota.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC s website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol OAS. Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.oasispetroleum.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website, other than the documents listed below, is not incorporated by reference into this Annual Report on Form 10-K.

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Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks related to the oil and natural gas industry and our business

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

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America, China, India and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and regional, domestic and international transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors supplies of oil and natural gas;

technological advances affecting energy consumption; and

the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than 12-month) contracts at market-based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. See Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves. See also 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 oil and natural gas reserves below.

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

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves below. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions and/or failure;
- unexpected operational events, including accidents;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as blizzards, ice storms and floods;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See Item 1. Business Our operations for information about our estimated oil and natural gas reserves and the PV-10 and Standardized Measure of discounted future net revenues as of December 31, 2011, 2010 and 2009.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Although the reserve information contained herein is reviewed by our independent reserve engineers, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Due to the limited production history of our undeveloped acreage, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

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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 oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2011, 2010 and 2009, we based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; 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 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 us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report on Form 10-K. Any significant future price changes will have a material effect on the quantity and present value of our proved reserves.

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

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

Part of our strategy involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Operations in the Bakken and the Three Forks formations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

Our experience with horizontal drilling utilizing the latest drilling and completion techniques specifically in the Bakken and Three Forks formations is limited. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or natural gas and oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future.

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

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Our cash flows used in investing activities were $613.2 million and $312.9 million (including $86.4 million for the acquisition of oil and gas properties in 2010) related to capital and exploration expenditures for the years ended December 31, 2011 and 2010, respectively. Our capital expenditure budget for 2012 is approximately $884 million, with approximately $758 million allocated for drilling and completion operations. Since our IPO, our capital expenditures have been financed with proceeds from our IPO, net cash provided by operating activities and proceeds from our $800 million of senior unsecured notes. DeGolyer and MacNaughton projects that we will incur capital costs (including abandonment obligations) in excess of $760 million over the next four years to develop the proved undeveloped reserves in the Williston Basin covered by its December 31, 2011 reserve report. Because these costs cover less than 10% of our total drilling locations, we will be required to generate or raise multiples of this amount of capital to develop all of our potential drilling locations should we elect to do so. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

A significant improvement in product prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through net proceeds from our $800 million of senior unsecured notes, cash flows provided by operating activities, 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 additional debt or equity securities or the sale of non-strategic assets. The issuance of additional debt or equity may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest 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. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under our revolving credit facility will be automatically reduced by an amount equal to 25% of the aggregate principal amount of such debt securities.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells and new projected wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas production;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

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

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

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount available under our revolving credit facility. 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 ability to borrow under our revolving credit facility and our results of operations for the periods in which such charges are taken.

We will not be the operator on all of our drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

We expect that we will not be the operator on approximately 40% of our identified gross drilling locations (approximately 10% of our identified net drilling locations). As we carry out our exploration and development programs, we may enter into arrangements with respect to existing or future drilling locations that result in a greater proportion of our locations being operated by others. As a result, we may have limited ability to exercise influence over the operations of the drilling locations operated by our partners. Dependence on the operator could prevent us from realizing our target returns for those locations. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator s expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations of some of our drilling locations may cause a material adverse effect on our results of operations and financial condition.

Substantially all of our producing properties and operations are located in the Williston Basin region, making us vulnerable to risks associated with operating in one major geographic area.

As of December 31, 2011, 100% of our proved reserves and production were located in the Williston Basin in northeastern Montana and northwestern North Dakota. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Williston Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our business depends on oil and natural gas gathering and transportation facilities, most of which are owned by third parties.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The unavailability of, or lack of, available 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. See also Market conditions or operational impediments may hinder our access to oil and natural gas markets or

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delay our production and Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices. We generally do not purchase firm transportation on third party pipeline facilities, and therefore, the transportation of our production can be interrupted by other customers that have firm arrangements.

The disruption of third-party facilities due to maintenance, weather or other interruptions of service could also negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored. A total shut-in of our production could materially affect us due to a resulting lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

The Williston Basin crude oil business environment has historically been characterized by periods when oil production has surpassed local transportation and refining capacity, resulting in substantial discounts in the price received for crude oil versus prices quoted for WTI crude oil. For example, the difference between the WTI crude oil price and quoted prices for Bakken Crude Oil on December 31, 2010 and 2011 was approximately negative $4.00 per barrel and negative $3.00 per barrel, respectively. Although additional Williston Basin transportation takeaway capacity was added in 2010 and 2011, production also increased due to the elevated drilling activity in these years. The increased production coupled with the planned turnaround at the Tesoro Corporation Mandan refinery and outages and disruptions on Enbridge s 6A and 6B lines caused price differentials at times to be at the high-end of the historical average range of approximately 10% to 15% of the WTI crude oil index price in 2010 and the first quarter of 2011. During the second and third quarters of 2011, the difference between WTI and ICE Brent crude oil (Brent) increased substantially, reaching its widest month in September 2011 when WTI traded at an average discount to Brent of $24.00 per barrel. During that same time, quoted prices for Bakken Crude Oil were at a premium to WTI, averaging approximately $5.00 per barrel above WTI. On barrels that are transported over pipelines to either Clearbrook or Guernsey, our realized price for crude oil is generally the quoted price for Bakken Crude Oil less transportation costs from the point where the crude oil is sold. During the fourth quarter of 2011, the difference between WTI and Brent decreased, and the quoted price for Bakken Crude Oil fell below WTI. Furthermore, in February 2012, the quoted prices for Bakken Crude Oil were substantially less than prices quoted for WTI due to refinery and transportation constraints. Such fluctuations and discounts could have a material adverse effect on our financial condition and results of operations.

The development of our proved undeveloped reserves in the Williston Basin and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 54% of our total proved reserves were classified as proved undeveloped as of December 31, 2011. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

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

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

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We may incur substantial losses and be subject to substantial liability claims as a result of our 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 oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- shortages of, or delays in, obtaining water for hydraulic fracturing activities;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing failure;
- personal injuries and death; and
- natural disasters.

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

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;

- suspension of our operations; and
- repair and remediation costs.

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

We have incurred losses in prior years and may do so again in the future.

For the year ended December 31, 2011, we had net income of $79.4 million. However, for the years ended December 31, 2010 and 2009, we incurred net losses of $29.7 million and $15.2 million, respectively. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures, including planned capital expenditures for 2012 of approximately $884 million.

The uncertainty and risks described in this Annual Report on Form 10-K may impede our ability to economically find, develop, exploit and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

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

We describe some of our drilling locations and our plans to explore those drilling locations in this Annual Report on Form 10-K. Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Williston Basin may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our potential drilling location inventories are scheduled to be drilled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2011, we had leases representing 31,905 net acres expiring in 2012, 35,055 net acres expiring in 2013 and 18,192 net acres expiring in 2014. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business. During the years ended December 31, 2011, 2010 and 2009, we recorded non-cash impairment charges of $3.6 million, $12.0 million and $5.4 million, respectively, for unproved property leases that expired during the period.

Our operations are subject to environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including the acquisition of a permit before conducting drilling or underground injection activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and waste water discharges related to our operations and due to historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our financial condition or results of well drilling, construction, completion on water management activities or operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties.

Our operations are substantially affected by federal, state and local laws and regulations, particularly as they relate to the regulation of oil and natural gas production and transportation. These laws and regulations include regulation of oil and natural gas exploration and production and related operations, including a variety of activities related to the drilling of wells, the interstate transportation of oil and natural gas by federal agencies such as the FERC, as well as state agencies. In addition, federal laws prohibit market manipulation in connection with the purchase or sale of oil and/or natural gas. Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties. Please see Other federal laws and regulations affecting our industry.

Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

Based on findings by the EPA in December 2009 that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the Earth s atmosphere and other climatic changes, the EPA adopted regulations under existing provisions of the federal Clean Air Act that restrict emissions of GHGs, including one that requires a reduction in emissions of GHGs from motor vehicles and another one that requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas production facilities, which may include certain of our operations. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption and implementation of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

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

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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

To a large extent, 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 Thomas B. Nusz, our Chairman, President and Chief Executive Officer, and Taylor L. Reid, our Executive Vice President and Chief Operating 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.

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

Oil and natural gas operations in the Williston Basin are adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities cannot be conducted as effectively during the winter months. Severe winter weather conditions limit and may temporarily halt our ability to operate during such conditions. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs.

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

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

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

In addition, some of these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivative activities to a separate entity, which may not be as creditworthy as the 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, 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, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if commodity prices decline as a consequence of the legislation and regulations. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

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Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- refinancing or restructuring our debt.

If for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on our senior unsecured notes. If amounts outstanding under our revolving credit facility or our senior unsecured notes were to be accelerated, we cannot be certain that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders. Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources.

Our revolving credit facility and the indentures governing our senior unsecured notes all contain operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit facility and the indentures governing our senior unsecured notes contain a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- pay distributions on, redeem or repurchase our common stock or redeem or repurchase our subordinated debt;
- make investments;

incur or guarantee additional indebtedness or issue preferred stock;

create or incur certain liens;

make certain acquisitions and investments;

redeem or prepay other debt;

enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;

consolidate, merge or transfer all or substantially all of our assets;

engage in transactions with affiliates;

create unrestricted subsidiaries;

enter into sale and leaseback transactions; and

engage in certain business activities.

As a result of these covenants, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions contained in our revolving credit facility and the indentures governing our senior unsecured notes may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit facility, the indentures governing our senior unsecured notes or any future indebtedness could result in an event of default under our revolving credit facility, the indentures governing our senior unsecured notes or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations.

If an event of default under our revolving credit facility occurs and remains uncured, the lenders thereunder:

would not be required to lend any additional amounts to us;

could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;

may have the ability to require us to apply all of our available cash to repay these borrowings; or

may prevent us from making debt service payments under our other agreements.

A payment default or an acceleration under our revolving credit facility could result in an event of default and an acceleration under the indentures for our senior unsecured notes. If the indebtedness under the notes were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. In addition, our obligations under our revolving credit facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the revolving credit facility, the lenders could seek to foreclose on our assets. Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources.

Our level of indebtedness may increase and reduce our financial flexibility.

As of December 31, 2011, we had no indebtedness outstanding under our revolving credit facility, $350 million available for future secured borrowings under our revolving credit facility and $800 million outstanding in senior unsecured notes. Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources Senior secured revolving line of credit and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources Senior unsecured notes. In the future, we may incur significant indebtedness in order to make future acquisitions or to develop our properties.

Our level of indebtedness could affect our operations in several ways, including the following:

a significant portion of our cash flows could be used to service our indebtedness;

a high level of debt would increase our vulnerability to general adverse economic and industry conditions;

the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;

our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;

a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;

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- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and

- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, and borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

In addition, our bank borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

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

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production ($52.2 million in receivables at December 31, 2011), which we market to energy marketing companies, refineries and affiliates, advances to joint interest parties ($3.9 million at December 31, 2011) and joint interest receivables ($67.3 million at December 31, 2011).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the year ended December 31, 2011, sales to Texon L.P., Plains All American Pipeline, L.P. and Enserco Energy Inc. accounted for approximately 18%, 16% and 15%, respectively, of our total sales. For the year ended December 31, 2010, sales to Plains All American Pipeline, L.P., Texon L.P. and Whiting Petroleum Corporation accounted for approximately 28%, 19% and 11%, respectively, of our total sales. For the year ended December 31, 2009, sales to Tesoro Refining and Marketing Company and Texon L.P. accounted for approximately 32% and 30%, respectively, of our total sales. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2011, 2010 and 2009. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

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 on which we wish to drill. We have limited ability to control participation in our wells. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

We may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;

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

- development and operating costs; and

potential environmental and other liabilities.

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

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management s attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be lower than we expect.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, or in oil and natural gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of an oil or gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in the title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may adversely impact our ability in the future to increase production and reserves. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

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

On September 12, 2011, President Obama sent to Congress a legislative package that includes proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, among other proposals, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities, and (iv) the extension of the amortization period for certain geological and geophysical expenditures.

These proposals also were included in President Obama s Proposed Fiscal Year 2012 Budget. It is unclear whether any such changes or similar changes will be enacted or, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and gas exploration and production. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Risks Relating to our Common Stock

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, our shareholders only opportunity to achieve a return on their investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our revolving credit facility and the indentures governing our senior unsecured notes. Consequently, our shareholders only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the shareholder sells their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the shareholder paid.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our Board of Directors to issue preferred stock without stockholder approval. If our Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

a classified Board of Directors, so that only approximately one-third of our directors are elected each year;

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- limitations on the removal of directors; and

- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the Board of Directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any interested stockholder, meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board of Directors.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by Item 2. is contained in Item 1. Business.

Item 3. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceeding. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us.

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

Market for Registrant s Common Equity. Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol OAS .

The following table sets forth the range of high and low sales prices of our common stock for the two most recent fiscal years as reported by the NYSE:

	xxxxxx	xxxxxx	xxxxxx	xxxxxx
	2011		2010	
	High	Low	High	Low
1st Quarter	$ 36.15	$ 25.76		
2nd Quarter (1)	$ 33.59	$ 25.54	$ 17.03	$ 14.27
3rd Quarter	$ 32.93	$ 20.27	$ 19.55	$ 13.88
4th Quarter	$ 33.65	$ 17.99	$ 29.36	$ 18.99

(1) For the second quarter of 2010, these prices represent the period from June 17, 2010, the date on which our common stock began trading on the NYSE, through June 30, 2010.

Holders. The number of shareholders of record of our common stock was approximately 25,839 on February 23, 2012.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility and the indentures governing our senior unsecured notes restrict the payment of cash dividends on our common stock. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

On February 24, 2012, the last sale price of our common stock, as reported on the NYSE, was $34.82 per share.

Unregistered Sales of Securities. There were no sales of unregistered securities during the year ended December 31, 2011.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2011:

Period	September 30, Total Number of Shares Exchanged (1)	September 30, Average Price Paid per Share	September 30, Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	September 30, Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
Oct 1 Oct 31, 2011	1,676	$ 22.33		
Nov 1 Nov 30, 2011	81	28.61		
Dec 1 Dec 31, 2011				
Total	1,757	$ 22.62		

(1) Represent shares that employees surrendered back to the Company that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards.

Stock Performance Graph. The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended (Exchange Act), except to the extent that we specifically request that such information be treated as soliciting material or specifically incorporate such information by reference into such a filing.

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The performance graph shown below compares the cumulative total return to Oasis common stockholders as compared to the cumulative total returns on the Standard and Poor s 500 Index (S&P 500) and the Standard and Poor s 500 Oil & Gas Exploration & Production Index (S&P 500 O&G E&P) since the time of our IPO. The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock at its initial public offering price of $14 per share and invested in the S&P 500 and the S&P 500 O&G E&P on June 16, 2010 at the closing price on such date; and

2. Dividends are reinvested.

Item 6. Selected Financial Data

Set forth below is our summary historical consolidated financial data for the years ended December 31, 2011, 2010, 2009 and 2008 and for the period from February 26, 2007, the date of our inception, through December 31, 2007, and balance sheet data at December 31, 2011, 2010, 2009, 2008 and 2007. This information may not be indicative of our future results of operations, financial position and cash flows and should be read in conjunction with the consolidated financial statements and notes thereto and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations presented elsewhere in this Annual Report on Form 10-K. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

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	September 30, 2011	September 30, 2010	September 30, 2009(2)	September 30, 2008	September 30, Period from February 26, 2007 (Inception) through December 31, 2007(1)
		Year ended December 31,			
		(In thousands, except per share data)			
Statement of operations data:					
Oil and gas revenues	$ 330,422	$ 128,927	$ 37,755	$ 34,736	$ 13,791
Expenses:					
Lease operating expenses	34,072	14,582	8,691	7,073	2,946
Production taxes	33,865	13,768	3,810	3,001	1,211
Depreciation, depletion and amortization	74,981	37,832	16,670	8,686	4,185
Exploration expenses	1,685	297	1,019	3,222	1,164
Rig termination(3)			3,000		
Impairment of oil and gas properties(4)	3,610	11,967	6,233	47,117	1,177
Loss (gain) on sale of properties	207		(1,455)		
Stock-based compensation expenses(5)		8,743			
General and administrative expenses	29,435	19,745	9,342	5,452	3,181
Total expenses	177,855	106,934	47,310	74,551	13,864
Operating income (loss)	152,567	21,993	(9,555)	(39,815)	(73)
Other income (expense):					
Net gain (loss) on derivative instruments	1,595	(7,653)	(4,747)	7,837	(11,741)
Interest expense	(29,618)	(1,357)	(912)	(2,404)	(1,776)
Other income (expense)	1,635	284	5	(9)	40
Total other income (expense)	(26,388)	(8,726)	(5,654)	5,424	(13,477)
Income (loss) before income taxes	126,179	13,267	(15,209)	(34,391)	(13,550)
Income tax expense(6)	46,789	42,962			
Net income (loss)	$ 79,390	$ (29,695)	$ (15,209)	$ (34,391)	$ (13,550)
Earnings (loss) per share:					
Basic and diluted	$ 0.86	$ (0.61)			

(1) For the period from February 26, 2007 through June 30, 2007, we did not engage in oil and gas operating or producing activities.

(2) Our statement of operations data for the year ended December 31, 2009 does not include the effects of the acquisition of interests in certain oil and gas properties from Kerogen Resources, Inc. and Fidelity Exploration and Production Company for the full twelve months of 2009. We acquired such interests on June 15, 2009 and September 30, 2009, respectively. See Note 6 to our audited consolidated financial statements.

(3) During the first quarter of 2009, we paid a total of $3.0 million in rig termination expenses in connection with early termination of two drilling rig contracts entered into in 2008.

(4) For the years ended December 31, 2011, 2010, 2009 and 2008 and for the period from February 26, 2007 (inception) through December 31, 2007, we recognized non-cash impairment charges on our unproved properties due to expiring leases of $3.6 million, $12.0 million, $5.4 million, $1.6 million and $1.2 million, respectively. In 2009 and 2008, we recognized a $0.8 million and $45.5 million non-cash impairment charge on our proved properties, respectively. See Note 2 to our audited consolidated financial statements.

(5) In March 2010, we recorded a $5.2 million stock-based compensation charge associated with Oasis Petroleum Management (OP Management) granting 1.0 million C Units to certain of our employees. During the fourth quarter of 2010, we recorded an additional $3.5 million in stock-based compensation expense primarily associated with OP Management granting discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors. See Note 10 to our audited consolidated financial statements.

(6) Prior to our corporate reorganization, we were a limited liability company not subject to entity-level taxation. Accordingly, no provision for federal or state corporate income taxes was recorded for the years ended December 31, 2009 and 2008 and for the period from February 26, 2007 (inception) through December 31, 2007 as the taxable income was allocated directly to our equity holders. In connection with the closing of our IPO in June 2010, we merged into a corporation and became subject to federal and state entity-level taxation. See Note 11 to our audited consolidated financial statements.

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	September 30, 2011	September 30, 2010	September 30, At December 31, 2009 (In thousands)	September 30, 2008	September 30, 2007
Balance sheet data:					
Cash and cash equivalents	$ 470,872	$ 143,520	$ 40,562	$ 1,570	$ 6,282
Net property, plant and equipment	1,079,955	483,683	181,573	114,220	92,918
Total assets	1,727,382	691,852	239,553	129,068	104,145
Long-term debt	800,000		35,000	26,000	46,500
Total stockholders /members equity	634,238	551,794	171,850	82,459	36,350

	September 30, 2011	September 30, Year ended December 31, 2010	September 30, 2009 (In thousands)	September 30, 2008	September 30, Period from February 26, 2007 (Inception) through December 31, 2007
Other financial data:					
Net cash provided by operating activities	$ 176,024	$ 49,612	$ 6,148	$ 13,766	$ 2,284
Net cash used in investing activities	(629,390)	(309,535)	(80,756)	(78,478)	(91,988)
Net cash provided by financing activities	780,718	362,881	113,600	60,000	95,986

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See Cautionary note regarding forward-looking statements.

Overview

We are an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources primarily in the Williston Basin. Since our inception, we have acquired properties that provide current production and significant upside potential through further development. Our drilling activity is primarily directed toward projects that we believe can provide us with repeatable successes in the Bakken formation.

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe will meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives. In addition, our willingness to acquire non-operated properties in new areas provides us with geophysical and geologic data that may lead to further acquisitions in the same area, whether on an operated or non-operated basis.

Oasis Petroleum LLC, our predecessor company, was formed in February 2007. In June 2007, we completed our initial acquisition of properties in the Williston Basin from Bill Barrett Corporation, which constitutes our accounting predecessor. We built our leasehold acreage position in the Williston Basin in three primary project areas (West Williston, East Nesson and Sanish) through the following acquisitions and development activities presented in the table below.

Project areas of acquired properties	September 30, Closing date of acquisition	September 30, Adjusted purchase price(1) (In millions)	September 30, Production at acquisition (Boe/d)	September 30, Approximate net acreage at acquisition
West Williston(2)	June 22, 2007	$ 83	1,000	175,000
East Nesson(3)	May 16, 2008	16		48,000
East Nesson/Sanish	June 15, 2009	27	800	37,000
East Nesson	September 30, 2009	11	300	46,000
West Williston	November 5, 2010	52	300	16,700
West Williston	December 10, 2010	30	200	10,000

(1) Represents initial purchase price plus closing adjustments.

(2) For accounting purposes, results from this West Williston acquisition are included in our results of operations effective July 1, 2007.

(3) Our farm-in and purchase arrangement required an initial payment of $15.6 million and obligated us to spend $15.1 million of drilling costs on behalf of the other parties.

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Our historical results include the results from our acquisitions beginning on the closing dates indicated in the table above. These acquisitions were financed with a combination of capital contributions made by EnCap and other private investors, borrowings under our revolving credit facility, cash flows provided by operating activities and proceeds from our IPO.

Our 2011, 2010 and 2009 activities included development and exploration drilling in each of our primary project areas. Our current activities are focused on evaluating and developing our asset base, optimizing our acreage positions and evaluating potential acquisitions. Based on the reserve reports prepared by our independent reserve engineers, we had 78.7 MMBoe of estimated proved reserves with a PV-10 of $1,903.7 million and a Standardized Measure of $1,319.5 million at December 31, 2011, 39.8 MMBoe of estimated proved reserves with a PV-10 of $697.8 million and a Standardized Measure of $485.7 million at December 31, 2010 and 13.3 MMBoe of estimated proved reserves with a PV-10 and a Standardized Measure of $133.5 million at December 31, 2009. Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $96.23/Bbl for oil and $4.12/MMBtu for natural gas for the year ended December 31, 2011, $79.40/Bbl for oil and $4.38/MMBtu for natural gas for the year ended December 31, 2010 and $61.04/Bbl for oil and $3.87/MMBtu for natural gas for the year ended December 31, 2009. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

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

Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations. Our quarterly average net realized oil prices and average price differentials are shown in the table below.

	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx	xxxx
	2009				Year ended December 31, 2009	2010				Year ended December 31, 2010	2011				Year ended December 31, 2011
	Q1	Q2	Q3	Q4		Q1	Q2	Q3	Q4		Q1	Q2	Q3	Q4	
Average Realized Oil Prices ($/Bbl)(1)	$30.68	$52.47	$57.00	$65.09	$55.32	$70.21	$67.19	$66.42	$73.05	$69.60	$82.33	$95.48	$83.52	$85.46	$86.18
Average Price Differential(2)	29%	13%	17%	14%	17%	11%	14%	13%	14%	13%	13%	7%	6%	10%	9%

(1) Realized oil prices do not include the effect of realized derivative contract settlements.

(2) Price differential compares realized oil prices to WTI crude oil index prices.

Changes in commodity prices may also significantly affect the economic viability of drilling projects as well as the economic valuation and economic recovery of oil and gas reserves. Oil prices have increased significantly since 2009. The higher commodity prices, as well as continued successes in the application of completion technologies in the Bakken formation, caused the active drilling rig count in the Williston Basin to exceed 210 rigs at December 31, 2011. Although additional Williston Basin transportation takeaway capacity was added in recent years, production also increased due to the elevated drilling activity. The increased production coupled with the planned turnaround at the Tesoro Corporation Mandan refinery and outages and disruptions on Enbridge s 6A and 6B lines caused price differentials at times to be at the high end of the historical average range of approximately 10% to 15% of the WTI crude oil index price in 2010 and the first quarter of 2011. During the second and third quarters of 2011, the difference between WTI and Brent increased substantially, reaching its widest month in September 2011 when WTI traded at an average discount to Brent of $24.00 per barrel. During that same time, quoted prices for Bakken Crude Oil were at a premium to WTI, averaging approximately $5.00 per barrel above WTI. On barrels that are transported over pipelines to either Clearbrook or

Guernsey, our realized price for crude oil is generally the quoted price for Bakken Crude Oil less transportation costs from the point where the crude oil is sold. During the fourth quarter of 2011, the difference between WTI and Brent decreased, and the quoted price for Bakken Crude Oil fell below WTI. Furthermore, in February 2012, the quoted prices for Bakken Crude Oil were substantially less than prices quoted for WTI due to refinery and transportation constraints.

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2011 Highlights

We completed and placed on production 63 gross (49.2) operated Bakken and Three Forks wells during 2011, and increased average daily production by 106% to 10,724 Boe per day from 5,206 Boe per day in 2010.

We increased total proved oil and natural gas reserves at December 31, 2011 to 78.7 MMBoe, a 98% increase over year-end 2010 proved reserves. Approximately 88% of proved reserves at year-end 2011 consisted of oil and 46% were classified as proved developed.

In 2011, we entered into new two-way and three-way collar options and deferred premium put contracts, all of which settle monthly based on the WTI crude oil index price. As of December 31, 2011, we had a total notional amount of 5,304,218 barrels in 2012, 2,787,500 barrels in 2013 and 217,000 barrels in 2014.

On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes due February 1, 2019, and on November 10, 2011, we issued $400 million of 6.5% senior unsecured notes due November 1, 2021. The issuance of these notes resulted in net proceeds to us of approximately $783 million, which we will use to fund our exploration, development and acquisition program and for general corporate purposes.

In June 2011, we formed Oasis Well Services LLC (OWS) to provide well services to OPNA. We expect OWS to begin operations late in the first quarter of 2012.

In July 2011, we formed Oasis Petroleum Marketing LLC (OPM) to provide marketing services to OPNA. During 2012, OPNA expects to sell a majority of its oil volumes directly to OPM, which will provide downstream gathering, transportation and marketing services to OPNA.

On October 6, 2011, we entered into our fifth amendment to our revolving credit facility, which reduced the interest rates payable on borrowings, extended the maturity date from February 26, 2015 to October 6, 2016, and increased our senior secured revolving line of credit from $600 million to $1 billion. In connection with the fifth amendment, the semi-annual redetermination of our borrowing base was completed on October 6, 2011, which resulted in the borrowing base of the revolving credit facility increasing from $137.5 million to $350 million.

In November 2011, we divested the last of our non-Williston Basin assets (Barnett shale properties).

At December 31, 2011, we had $490.9 million of cash, cash equivalents and short-term investments and had no outstanding debt or outstanding letters of credit under our revolving credit facility.

As of December 31, 2011, we had nine operated rigs running and we have three additional rigs under contract to be delivered in 2012.

Our 2012 capital expenditure budget is $884 million, a 41% increase over our 2011 capital budget of $627 million. The 2012 budget consists of:

$758 million of development capital for operated and non-operated wells (including expected savings from services provided by OWS);

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$57 million for constructing infrastructure to support production in our core project areas, primarily related to salt water disposal systems that will lower lease operating expenses;

$25 million for maintaining and expanding our leasehold position;

$6 million for micro-seismic work, purchase of seismic data and other test work;

$15 million for OWS, including $12 million for equipment budgeted and ordered in 2011 that will arrive in the first quarter of 2012; and

$23 million for other non-E&P capital, including items such as district tools, administrative capital and capitalized interest.

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production and do not include the effects of derivatives. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

The following table summarizes our revenues and production data for the periods indicated.

	September 30,	September 30, Year ended December 31,	September 30,
	2011	**2010**	**2009(1)**
Operating results (in thousands):			
Revenues			
Oil	$ 321,668	$ 124,682	$ 36,376
Natural gas	8,754	4,245	1,379
Total oil and gas revenues	$ 330,422	$ 128,927	$ 37,755
Production data:			
Oil (MBbls)	3,732	1,792	658
Natural gas (MMcf)	1,092	651	326
Oil equivalents (MBoe)	3,914	1,900	712
Average daily production (Boe/d)	10,724	5,206	1,950
Average sales prices:			
Oil, without realized derivatives (per Bbl)	$ 86.18	$ 69.60	$ 55.32
Oil, with realized derivatives (per Bbl) (2)	85.15	69.53	58.82
Natural gas (per Mcf) (3)	8.02	6.52	4.24

(1) Our statement of operations data for the year ended December 31, 2009 does not include the effects of the acquisition of interests in certain oil and gas properties from Kerogen Resources, Inc. and Fidelity Exploration and Production Company for the full twelve months of 2009. We acquired such interests on June 15, 2009 and September 30, 2009, respectively. See Note 6 to our audited consolidated financial statements.

(2) Realized prices include realized gains or losses on cash settlements for our commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes.

(3) Natural gas prices include the value for natural gas and natural gas liquids.

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

Oil and natural gas revenues. Our oil and natural gas sales revenues increased $201.5 million, or 156%, to $330.4 million during the year ended December 31, 2011 as compared to the year ended December 31, 2010. Our revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 5,518 Boe per day, or 106%, to 10,724 Boe per day during the year ended December 31, 2011 as compared to the year ended December 31, 2010. The increase in average daily production sold was primarily a result of our well completions during 2011. These well completions in our West Williston, East Nesson and Sanish project areas increased average daily production by approximately 4,121 Boe per day, 936 Boe per day and 437 Boe per day, respectively, during 2011. The higher production amounts sold increased revenues by $170.8 million, and the remaining $30.7 million increase in revenues was attributable to higher oil and natural gas sales prices during the year ended December 31, 2011. Average oil sales prices, without realized derivatives, increased by $16.58/Bbl, or 24%, to an average of $86.18/Bbl for the year ended December 31, 2011 as compared to the year ended December 31, 2010.

Year ended December 31, 2010 as compared to year ended December 31, 2009

Oil and natural gas revenues. Our oil and natural gas sales revenues increased $91.2 million, or 241%, to $128.9 million during the year ended December 31, 2010 as compared to the year ended December 31, 2009. Our revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 3,256 Boe per day, or 167%, to 5,206 Boe per day during the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase in average daily production sold was primarily a result of our well completions during 2010. These well completions in our West Williston, East Nesson and Sanish project areas increased average daily production by approximately 1,181 Boe per day, 975 Boe per day and 748 Boe per day, respectively, during 2010. The higher production amounts sold increased revenues by $81.1 million, and the remaining $10.1 million increase in revenues was attributable to higher oil sales prices during the year ended December 31, 2010. Average oil sales prices, without realized derivatives, increased by $14.28/Bbl, or 26%, to an average of $69.60/Bbl for the year ended December 31, 2010 as compared to the year ended December 31, 2009.

Expenses

The following table summarizes our operating expenses for the periods indicated.

	September 30,	September 30,	September 30,
		Year ended December 31,	
	2011	2010	2009(1)
		(In thousands, except per Boe of production)	
Statement of operations data:			
Expenses:			
Lease operating expenses	$ 34,072	$ 14,582	$ 8,691
Production taxes	33,865	13,768	3,810
Depreciation, depletion and amortization	74,981	37,832	16,670
Exploration expenses	1,685	297	1,019
Rig termination(2)			3,000
Impairment of oil and gas properties	3,610	11,967	6,233
Loss (gain) on sale of properties	207		(1,455)
Stock-based compensation expenses(3)		8,743	
General and administrative expenses	29,435	19,745	9,342
Total expenses	177,855	106,934	47,310
Operating income (loss)	152,567	21,993	(9,555)
Other income (expense):			
Net change in gain (loss) on derivative instruments	1,595	(7,653)	(4,747)
Interest expense	(29,618)	(1,357)	(912)
Other income (expense)	1,635	284	5
Total other income (expense)	(26,388)	(8,726)	(5,654)
Income (loss) before income taxes	126,179	13,267	(15,209)
Income tax expense(4)	46,789	42,962	
Net income (loss)	$ 79,390	$ (29,695)	$ (15,209)
Costs and expenses (per Boe of production):			
Lease operating expenses	$ 8.70	$ 7.67	$ 12.21
Production taxes	8.65	7.25	5.35
Depreciation, depletion and amortization	19.16	19.91	23.42
General and administrative expenses	7.52	10.39	13.12
Stock-based compensation expenses(3)		4.60	

(1) Our statement of operations data for the year ended December 31, 2009 does not include the effects of the acquisition of interests in certain oil and gas properties from Kerogen Resources, Inc. and Fidelity Exploration and Production Company for the full twelve months of 2009. We acquired such interests on June 15, 2009 and September 30, 2009, respectively. See Note 6 to our audited consolidated financial statements.

(2) During the first quarter of 2009, we paid a total of $3.0 million in rig termination expenses in connection with early termination of two drilling rig contracts entered into in 2008.

(3) In March 2010, we recorded a $5.2 million stock-based compensation charge associated with OP Management granting 1.0 million C Units to certain of our employees. During the fourth quarter of 2010, we recorded an additional $3.5 million in stock-based compensation expense primarily associated with OP Management granting discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors. See Note 10 to our audited consolidated financial statements.

(4) Prior to our corporate reorganization, we were a limited liability company not subject to entity-level taxation. Accordingly, no provision for federal or state corporate income taxes was recorded for the year ended December 31, 2009 as our taxable income was allocated directly to our equity holders. In connection with the closing of our IPO in June 2010, we merged into a corporation and became subject to federal and state entity-level taxation. See Note 11 to our audited consolidated financial statements.

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

Lease operating expenses. Lease operating expenses increased $19.5 million to $34.1 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. This increase was primarily due to an increased number of producing wells from our West Williston acquisitions that were completed in the fourth quarter of 2010 and to our well completions during 2011. The unit operating costs increased from $7.67 for the year ended December 31, 2010 to $8.70 for the year ended December 31, 2011, primarily due to increased costs associated with water production, salt water disposal and the continuing effects of the inclement weather during the first half of 2011. We have $57 million of capital in our 2012 budget primarily allocated to building salt water disposal infrastructure, which is currently being deployed in our key operating areas. This infrastructure is expected to eliminate the need for trucks and simplify operational logistics. We are projecting unit operating costs in 2012 to range between $6.00 to $8.00 per Boe compared to $8.70 in 2011.

Production taxes. Our production taxes for the years ended December 31, 2011 and 2010 were 10.2% and 10.7%, respectively, as a percentage of oil and natural gas sales. The 2011 production tax rate was lower than the 2010 production tax rate due to the increased weighting of oil revenues in Montana, which imposes a lower production tax rate than North Dakota. Our production taxes for the year ended December 31, 2010 were primarily for oil and natural gas sales revenue associated with properties in the North Dakota portion of our West Williston project area, which generate revenues subject to an 11.5% production tax rate.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $37.1 million to $75.0 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. The increase in DD&A expense for the year ended December 31, 2011 was primarily a result of our production increases and well completions during 2011. The DD&A rate for the year ended December 31, 2011 was $19.16 per Boe compared to $19.91 per Boe for the year ended December 31, 2010. The lower DD&A rate was due to the lower cost of reserve additions associated with our 2011 drilling activities.

Impairment of oil and gas properties. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2011 and 2010. During the years ended December 31, 2011 and 2010, we recorded non-cash impairment charges of $3.6 million and $12.0 million, respectively, for unproved property leases that expired during the period. In determining the amount of the non-cash impairment charges for such periods, we considered the application of the factors described under Critical accounting policies and estimates Impairment of proved properties and Critical accounting policies and estimates Impairment of unproved properties. As of December 31, 2011, we did not record an impairment charge with respect to any acreage expiring in 2012 based primarily on our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that would otherwise expire.

Stock-based compensation expenses. For the year ended December 31, 2010, we recorded $8.7 million of primarily non-cash charges for stock-based compensation expense associated with OP Management s grant of C Units to certain of our employees in March 2010 and grant of discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors in the fourth quarter of 2010. Based on the characteristics of these awards, we concluded that they represented equity-type awards and we accounted for the value of these awards as if they had been awarded by us. We used fair-value-based methods to determine the value of stock-based compensation awarded to our employees and contractors and recognized the entire amount as expense due to the immediate vesting of the awards, with no future requisite service period required by the employees. As of December 31, 2010, OP Management had distributed substantially all cash or requisite common stock to its members based on membership interests and distribution percentages. No stock-based compensation expense was recorded for the year ended December 31, 2011 related to the C Units or discretionary shares.

General and administrative. Our general and administrative expenses increased $9.7 million for the year ended December 31, 2011 from $19.7 million for the year ended December 31, 2010. Of this increase, approximately $6.5 million was due to the impact of our organizational growth on employee compensation and $2.4 million was due to the amortization of our restricted stock awards. As of December 31, 2011, we had 146 full-time employees compared to 62 full-time employees as of December 31, 2010.

Derivatives. As a result of our derivative activities, we incurred net cash settlement losses of $3.8 million and $0.1 million for the years ended December 31, 2011 and 2010, respectively. In addition, as a result of forward oil price changes, we recognized a $5.4 million non-cash unrealized mark-to-market derivative gain during the year ended December 31, 2011 and a $7.5 million non-cash unrealized mark-to-market derivative loss during the year ended December 31, 2010.

Interest expense. Interest expense increased $28.3 million to $29.6 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. The increase was due to the interest related to our 7.25% and 6.5% senior unsecured notes issued in February and November, 2011, respectively. For the year ended December 31, 2011, we incurred no borrowings under our revolving credit facility compared to a weighted average debt balance of $15.3 million for the year ended December 31, 2010. We capitalized $3.1 million of interest costs for the year ended December 31, 2011, which will be amortized over the life of the related assets. No interest costs were capitalized for the year ended December 31, 2010.

Income tax expense. Income tax expense increased $3.8 million to $46.8 million for the year ended December 31, 2011 compared to the year ended December 31, 2010. For the year ended December 31, 2011, our effective tax rate was 37.1% compared to 323.8% for the year ended December 31, 2010. Prior to our corporate reorganization in June 2010, no provision for federal or state income taxes was recorded, as the Company was a limited liability company and not subject to federal or state income tax. In 2010, we recorded an estimated net deferred tax expense of $35.6 million to recognize a deferred tax liability for the initial book and tax basis differences. Prospectively, we expect our annual effective tax rate to be between 37% and 39%. Our effective tax rate for 2011 differs from the federal statutory rate of 35% due to the effect of state income taxes. For 2010, our effective tax rate differs from the federal statutory rate of 35% due to the effect of the initial deferred tax expense, certain non-deductible IPO-related costs, non-deductible stock-based compensation expenses and state income taxes.

Year ended December 31, 2010 compared to year ended December 31, 2009

Lease operating expenses. Lease operating expenses increased $5.9 million to $14.6 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. This increase was primarily due to our 2010 well completions. The 167% increase in production volumes from the year ended December 31, 2009 to the year ended December 31, 2010 resulted in a 37% decrease in unit operating costs to $7.67 per Boe.

Production taxes. Our production taxes for the years ended December 31, 2010 and 2009 were 10.7% and 10.1%, respectively, as a percentage of oil and natural gas sales. The 2010 production tax rate was higher than the 2009 production tax rate due to the increased weighting of oil revenues in North Dakota, which imposes an 11.5% production tax rate. Our production taxes for the year ended December 31, 2009 were primarily for oil and natural gas sales revenue associated with properties in the Montana portion of our West Williston project area, which generate revenues subject to lower production tax rates in Montana.

DD&A. DD&A expense increased $21.2 million to $37.8 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increase in DD&A expense for the year ended December 31, 2010 was primarily due to the production increases from the Sanish and East Nesson acquisitions completed at the end of the second and third quarters of 2009, respectively, and as a result of our well completions during the fourth quarter of 2009 and all of 2010. The DD&A rate for the year ended December 31, 2010 was $19.91 per Boe compared to $23.42 per Boe for the year ended December 31, 2009. The lower DD&A rate was due to the lower cost of reserve additions associated with our 2009 Sanish and East Nesson acquisitions and our 2010 drilling activities.

Rig termination. During the first quarter of 2009, we paid a total of $3.0 million in rig termination expenses in connection with the early termination of two drilling rig contracts entered into in 2008. We did not have any rig termination expenses during the year ended December 31, 2010.

Impairment of oil and gas properties. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2010. During the year ended December 31, 2009, we recorded a non-cash impairment charge of $0.8 million on our proved oil and gas properties. During the years ended December 31, 2010 and 2009, we recorded non-cash impairment charges of $12.0 million and $5.4 million, respectively, for unproved property leases that expired during the period. In determining the amount of the non-cash impairment charges for such periods, we considered the application of the factors described under Critical accounting policies and estimates Impairment of proved properties and Critical accounting policies and estimates Impairment of unproved properties. As of December 31, 2010, we did not record an impairment charge with respect to any acreage expiring in 2011 based primarily on our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that would otherwise expire.

Stock-based compensation expenses. For the year ended December 31, 2010, we recorded $8.7 million of primarily non-cash charges for stock-based compensation expense associated with OP Management s grant of C Units to certain of our employees in March 2010 and grant of discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors in the fourth quarter of 2010. Based on the characteristics of these awards, we concluded that they represented equity-type awards and we accounted for the value of these awards as if they had been awarded by us. We used fair-value-based methods to determine the value of stock-based compensation awarded to our employees and contractors and recognized the entire amount as expense due to the immediate vesting of the awards, with no future requisite service period required by the employees. No stock-based compensation expense was recorded for the year ended December 31, 2009 because we had not historically issued stock-based compensation awards to our employees.

General and administrative. Our general and administrative expenses increased $10.4 million for the year ended December 31, 2010 from $9.3 million for the year ended December 31, 2009. Of this increase, approximately $4.2 million was due to higher advisory, audit, legal, tax and filing fees primarily related to our IPO and additional costs of being a public entity. In addition, we recorded approximately $1.2 million of amortization of our restricted stock awards for the year ended December 31, 2010. The remaining increase was primarily due to higher costs related to employee compensation (including bonuses paid during the first quarter of 2010 and accrued bonuses to be paid in the first quarter of 2011) and contract labor. As of December 31, 2010, we had 62 full-time employees compared to 27 full-time employees as of December 31, 2009.

Derivatives. As a result of our derivative activities, we incurred a cash settlement loss of $0.1 million for the year ended December 31, 2010 and a cash settlement gain of $2.3 million for the year ended December 31, 2009. In addition, as a result of forward oil price changes, we recognized $7.5 million and $7.0 million of non-cash unrealized mark-to-market derivative losses during the years ended December 31, 2010 and 2009, respectively.

Interest expense. Interest expense increased $0.4 million to $1.4 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increase was the result of higher monthly amortization on our deferred financing costs related to our amended revolving credit facility coupled with the write-off of the deferred financing costs related to the original revolving credit facility in February 2010. Our weighted average debt balance decreased to $15.3 million for the year ended December 31, 2010 from $22.8 million for the year ended December 31, 2009 as we incurred no borrowings during the last six months of 2010. The weighted average interest rate on our revolving credit facility borrowings decreased to 3.1% for the year ended December 31, 2010 from 3.5% for the year ended December 31, 2009. No interest costs were capitalized for the years ended December 31, 2010 and 2009.

Income tax expense. Prior to our corporate reorganization, we were a limited liability company not subject to entity-level income tax. Accordingly, no provision for federal or state corporate income taxes was recorded for the year ended December 31, 2009 as our taxable income was allocated directly to our equity holders. In connection with the closing of our IPO, we merged into a corporation and became subject to federal and state entity-level taxation. In connection with our corporate reorganization, an initial net deferred tax liability of $29.2 million was established for differences between the tax and book basis of our assets and liabilities and a corresponding deferred tax expense was recorded in our Consolidated Statement of Operations. We recorded additional deferred tax expenses of $6.2 million and $0.2 million in September 2010 and December 2010, respectively, for discrete adjustments related to changes in estimate of the initial deferred tax liability recorded in June 2010 and certain non-deductible IPO and non-deductible stock-based compensation related expenses. Subsequent to our corporate reorganization, we recorded federal and state income tax expense of $7.4 million on pre-tax income earned in the post-reorganization period from June 17, 2010 (the effective date of the reorganization) to December 31, 2010.

Liquidity and capital resources

Our primary sources of liquidity as of the date of this report have been proceeds from our senior unsecured notes issued during 2011, proceeds from our IPO, cash flows from operations and historically, borrowings under our revolving credit facility and capital contributions from EnCap and other private investors. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. We continually monitor potential capital sources, including equity and debt financings, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

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On June 22, 2010, we completed an IPO of 48,300,000 shares of common stock at $14.00 per share. We sold 30,370,000 shares of common stock in the offering and OAS Holding Company LLC (OAS Holdco), the selling stockholder, sold 17,930,000 shares of common stock, including 6,300,000 shares sold by OAS Holdco pursuant to the full exercise of the underwriters over-allotment option. We received net proceeds from the offering of $399.7 million, after deducting underwriting discounts and estimated offering expenses. We used a portion of these net proceeds to repay all outstanding indebtedness of $75.0 million under our revolving credit facility, and the remaining proceeds are being used to fund our exploration, development and acquisition program and for general corporate purposes. We did not receive any proceeds from the sale of shares by OAS Holdco.

On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes due February 1, 2019, and on November 10, 2011 we issued $400 million of 6.5% senior unsecured notes due November 1, 2021. Interest is payable on these notes semi-annually in arrears. These notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these notes resulted in net proceeds to us of approximately $783 million, which we will use to fund our exploration, development and acquisition program and for general corporate purposes. See Senior unsecured notes below.

In connection with the fourth amendment to our revolving credit facility, a redetermination of our borrowing base was completed at our request on January 21, 2011, in lieu of the scheduled April 1, 2011 semi-annual redetermination. As a result of this redetermination, our borrowing base increased from $120 million to $150 million. However, in connection with the issuance of our 7.25% senior unsecured notes discussed below, our borrowing base was automatically decreased to $137.5 million. On October 6, 2011, we entered into the fifth amendment to our revolving credit facility. This amendment reduced the interest rates payable on borrowings under our revolving credit facility, extended the maturity date of our revolving credit facility from February 26, 2015 to October 6, 2016 and increased our senior secured revolving line of credit from $600 million to $1 billion. In connection with the fifth amendment, the semi-annual redetermination of our borrowing base was also completed on October 6, 2011, which resulted in the borrowing base of the revolving credit facility increasing from $137.5 million to $350 million. As of December 31, 2011, we had no outstanding indebtedness under our revolving credit facility. See Senior secured revolving line of credit below.

In 2011, we spent $666.0 million on capital expenditures, which represented a 89% increase over the $352.4 million invested during 2010. This increase was a result of (i) improved industry conditions and technology in the Bakken formation as well as increased economics in the area, (ii) an increase in total net wells drilled in 2011 and (iii) additional lease acquisitions. See Cash flows used in investing activities below.

Our total 2012 capital expenditure budget is $884 million, which consists of:

- $758 million of development capital for operated and non-operated wells (including expected savings from services provided by OWS);
- $57 million for constructing infrastructure to support production in our core project areas, primarily related to salt water disposal systems that will lower lease operating expenses;
- $25 million for maintaining and expanding our leasehold position;
- $6 million for micro-seismic work, purchase of seismic data and other test work;
- $15 million for OWS, including $12 million for equipment budgeted and ordered in 2011 that will arrive in the first quarter 2012; and
- $23 million for other non-E&P capital, including items such as district tools, administrative capital and capitalized interest.

While we have budgeted $884 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling and operations results as the year progresses. We believe that the net proceeds from our senior unsecured notes issued in 2011 together with cash on hand and cash flows from operating activities should be more than sufficient to fund our 2012 capital expenditure budget. However, because the operated wells funded by our 2012 drilling plan represent only a small percentage of our gross identified drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of identified drilling locations should we elect to do so.

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Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

We expect that in the future our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and natural gas. Please see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We actively review acquisition opportunities on an ongoing basis. Our ability to make significant additional acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us or at all.

Cash flow activity

Our cash flows for the years ended December 31, 2011, 2010 and 2009 are presented below:

	September 30,	September 30,	September 30,
		Year Ended December 31,	
	2011	2010	2009
		(In thousands)	
Net cash provided by operating activities	$ 176,024	$ 49,612	$ 6,148
Net cash used in investing activities	(629,390)	(309,535)	(80,756)
Net cash provided by financing activities	780,718	362,881	113,600
Net change in cash	$ 327,352	$ 102,958	$ 38,992

Cash flows provided by operating activities

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in oil prices on a portion of our production, thereby mitigating our exposure to oil price declines, but these transactions may also limit our cash flow in periods of rising oil prices. For additional information on the impact of changing prices on our financial position, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Net cash provided by operating activities was $176.0 million, $49.6 million and $6.1 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increase in cash flows provided by operating activities for the year ended December 31, 2011 as compared to 2010 was primarily the result of an increase in oil and natural gas production of 106%. In addition, at December 31, 2011, we had a working capital surplus of $441.1 million. This surplus for 2011 was primarily attributable to our cash balance as a result of the proceeds from the issuance of our senior unsecured notes in 2011. The increase in cash flows provided by operating activities for the year ended December 31, 2010 as compared to 2009 was primarily the result of an increase in oil and natural gas production of 167%. In addition, at December 31, 2010, we had a working capital surplus of $123.6 million. This surplus for 2010 was primarily attributable to our cash balance as a result of the proceeds from the sale of common stock in our IPO.

Cash flows used in investing activities

We had cash flows used in investing activities of $629.4 million, $309.5 million and $80.8 million during the years ended December 31, 2011, 2010 and 2009, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. The increase in cash used in investing activities for the year ended December 31, 2011 compared to 2010 of $319.9 million was attributable to increased levels of expenditures for the development of our properties. The increase in cash used in investing activities for the year ended December 31, 2010 compared to 2009 of $228.7 million was attributable to our acquisitions of properties in the West Williston project area, as well as increased levels of expenditures for the development of our properties.

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Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. Our capital expenditures for drilling, development and acquisition costs for the years ended December 31, 2011, 2010 and 2009 are summarized in the following table:

	September 30,	September 30, Year ended December 31,	September 30,
	2011	2010 (In thousands)	2009
E&P capital expenditures by project area:			
West Williston	$ 499,558	$ 240,830	$ 15,521
East Nesson	110,013	73,529	40,208
Sanish	27,436	30,854	32,952
Other (1)	282	429	582
Total E&P capital expenditures	637,289	345,642	89,263
Non-E&P capital expenditures (2)	28,685	6,773	119
Total capital expenditures (3)	$ 665,974	$ 352,415	$ 89,382

(1) Other capital expenditures represent data relating to our properties in the Barnett shale, which we sold in November 2011.

(2) Non-E&P capital expenditures include such items as district tools, administrative capital and capitalized interest.

(3) Capital expenditures reflected in the table above differ from the amounts shown in the statement of cash flows in our consolidated financial statements because amounts reflected in the table include changes in accrued liabilities from the previous reporting period for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis.

During 2011, we participated in drilling and completion of 135 gross wells (53.6 net) and, as operator, we drilled and completed 63 gross (49.2 net) of these wells. In addition, as of December 31, 2011, there were 25 gross (19.6 net) operated wells awaiting completion and 7 gross (4.8 net) operated wells in the process of drilling in the Bakken and Three Forks formations. Our land leasing and acquisition activity is focused in and around our existing core consolidated land positions, primarily in the West Williston.

We anticipate investing $846 million for capital expenditures for drilling, development and acquisition costs in 2012 as follows:

	September 30, (In thousands)
Drilling and completing wells	$ 758,000
Constructing infrastructure to support production in our core project areas	57,000
Maintaining and expanding our leasehold position	25,000
Micro-seismic work, purchasing seismic data and other test work	6,000
Total E&P capital expenditures	846,000
Non-E&P capital expenditures	38,000
Total capital expenditures	$ 884,000

Cash flows provided by financing activities

Net cash provided by financing activities was $780.7 million, $362.9 million and $113.6 million for the years ended December 31, 2011, 2010 and 2009, respectively. For the year ended December 31, 2011, cash sourced through financing activities was primarily provided by net proceeds from the issuance of our senior unsecured notes. For the year ended December 31, 2010, cash sourced through financing activities was primarily provided by net proceeds from the sale of the common stock in our IPO. For the year ended December 31, 2009, cash sourced through financing activities was primarily provided by capital contributions from EnCap and other private investors and borrowings under our revolving credit facility.

For the year ended December 31, 2011, we had no borrowings and no outstanding letters of credit issued under our revolving credit facility, resulting in an unused borrowing base capacity of $350 million as of December 31, 2011. We were in compliance with the financial covenants of our revolving credit facility as of December 31, 2011.

As of December 31, 2010, we had no borrowings and $25,000 of outstanding letters of credit issued under our revolving credit facility. The weighted average debt outstanding for the year ended December 31, 2010 was $15.3 million. The weighted average interest rate incurred on the outstanding borrowings for the year ended December 31, 2010 was 3.1%.

Senior secured revolving line of credit

Oasis Petroleum LLC, as parent, and OPNA, as borrower, entered into a credit agreement dated June 22, 2007 (as amended and restated, the Amended Credit Facility). The Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. In connection with the fourth amendment to our Amended Credit Facility, a redetermination of our borrowing base was completed at our request on January 21, 2011, in lieu of the scheduled April 1, 2011 semi-annual redetermination. As a result of this redetermination, our borrowing base increased from $120 million to $150 million. However, in connection with the issuance of our 7.25% senior unsecured notes discussed below, our borrowing base was automatically decreased to $137.5 million. Subsequently, we entered into our fifth amendment to our Amended Credit Facility on October 6, 2011. This amendment reduced the interest rates payable on our borrowings under the Amended Credit Facility, extended the maturity date of the Amended Credit Facility from February 26, 2015 to October 6, 2016, and increased our senior secured revolving line of credit from $600 million to $1 billion. In connection with this amendment, the semi-annual redetermination of our borrowing base was also completed on October 6, 2011, which resulted in the borrowing base of our Amended Credit Facility increasing from $137.5 million to $350 million. In addition, on October 25, 2011, the lenders under the Amended Credit Facility (Lenders) waived the mandatory reduction of the borrowing base that otherwise would have occurred as a result of the issuance of the senior unsecured notes subsequently offered (see Senior Unsecured 2021 Notes below). Borrowings under our Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports.

Borrowings under the Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate (LIBOR) loan or a domestic bank prime interest rate loan (defined in the Amended Credit Facility as an Alternate Based Rate or ABR loan). As of December 31, 2011, any outstanding LIBOR and ABR loans would have beared their respective interest rates plus the applicable margin indicated in the following table:

Ratio of Total Outstanding Borrowings to Borrowing Base	September 30, Applicable Margin for LIBOR Loans	September 30, Applicable Margin for ABR Loans
Less than .25 to 1	1.50%	0.00%
Greater than or equal to .25 to 1 but less than .50 to 1	1.75%	0.25%
Greater than or equal to .50 to 1 but less than .75 to 1	2.00%	0.50%
Greater than or equal to .75 to 1 but less than .90 to 1	2.25%	0.75%
Greater than .90 to 1 but less than or equal 1	2.50%	1.00%

An ABR loan does not have a set maturity date and may be repaid at any time we provide advance notification to the Lenders. Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. We have the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the Lenders. The minimum available loan term is one month and the maximum loan term is six months for LIBOR-based loans. Interest for LIBOR loans is paid upon maturity of the loan term. Interim interest is paid every three months for LIBOR loans that have loan terms that are greater than three months in duration. At the end of a LIBOR loan term, the Amended Credit Facility allows us to elect to continue a LIBOR loan with the same or a differing loan term or convert the borrowing to an ABR loan.

On a quarterly basis, we also pay a 0.375% (as of December 31, 2011) annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

The Amended Credit Facility contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;

- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;

a prohibition against making investments, loans and advances, subject to permitted exceptions;

restrictions on creating liens and leases on our assets and our subsidiaries, subject to permitted exceptions;

restrictions on merging and selling assets outside the ordinary course of business;

restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;

a provision limiting oil and natural gas derivative financial instruments;

a requirement that we not allow a ratio of Total Net Debt (as defined in the Amended Credit Facility) to consolidated EBITDAX (as defined in the Amended Credit Facility) to be greater than 4.0 to 1.0 for the four quarters ended on the last day of each quarter; and

a requirement that we maintain a Current Ratio (as defined in the Amended Credit Facility) of consolidated current assets (with exclusions as described in the Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Amended Credit Facility) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The Amended Credit Facility contains customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under the Amended Credit Facility to be immediately due and payable.

As of December 31, 2011, we had no borrowings and no outstanding letters of credit issued under the Amended Credit Facility, resulting in an unused borrowing base capacity of $350 million. We were also in compliance with the financial covenants of the Amended Credit Facility as of December 31, 2011.

Senior unsecured notes

Senior Unsecured 2019 Notes On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes (the 2019 Notes) due February 1, 2019. Interest is payable on the 2019 Notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The 2019 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2019 Notes resulted in net proceeds to us of approximately $390 million, which we will use to fund our exploration, development and acquisition program and for general corporate purposes.

At any time prior to February 1, 2014, we may redeem up to 35% of the 2019 Notes at a redemption price of 107.25% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2019 Notes remains outstanding after such redemption. Prior to February 1, 2015, we may redeem some or all of the 2019 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 1, 2015, we may redeem some or all of the 2019 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning February 1, 2016 and 100.00% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2019 Notes restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2019 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no default (as defined in the indenture) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Senior Unsecured 2021 Notes On November 10, 2011, we issued $400 million of 6.5% senior unsecured notes (the 2021 Notes) due November 1, 2021. Interest is payable on the 2021 Notes semi-annually in arrears on each May 1 and November 1, commencing May 1, 2012. The 2021 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2021 Notes resulted in net proceeds to us of approximately $393 million, which we will use to fund our exploration, development and acquisition program and for general corporate purposes.

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At any time prior to November 1, 2014, we may redeem up to 35% of the 2021 Notes at a redemption price of 106.5% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2021 Notes remains outstanding after such redemption. Prior to November 1, 2016, we may redeem some or all of the 2021 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after November 1, 2016, we may redeem some or all of the 2021 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.25% for the twelve-month period beginning on November 1, 2016, 102.167% for the twelve-month period beginning November 1, 2017, 101.083% for the twelve-month period beginning on November 1, 2018 and 100.00% beginning on November 1, 2019, plus accrued and unpaid interest to the redemption date. If a change in control occurs at any time on or prior to January 1, 2013, we may redeem all, but not less than all, of the 2021 Notes, at a redemption price equal to 110% of the principal amount plus accrued and unpaid interest to the redemption date.

The indenture governing the 2021 Notes restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2021 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no default (as defined in the indenture) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2011 (in thousands):

	September 30,	September 30,	September 30, Payments due by period	September 30,	September 30,
Contractual obligations	**Total**	**Within 1 year**	**2-3 years**	**4-5 years**	**More than 5 years**
Operating leases(1)	$ 12,776	$ 2,031	$ 4,479	$ 4,555	$ 1,711
Drilling rig commitments(1)	63,247	19,464	42,128	1,655	
Volume commitment agreements(1)	54,522	659	13,881	15,610	24,372
Fracturing service agreements(1)	102,375	102,375			
Senior unsecured notes(2)	800,000				800,000
Interest payments on senior unsecured notes (2)	476,850	54,350	110,000	110,000	202,500
Asset retirement obligations(3)	13,075		1,482	611	10,982
Total contractual cash obligations	$ 1,522,845	$ 178,879	$ 171,970	$ 132,431	$ 1,039,565

(1) See Note 14 to our audited consolidated financial statements for a description of our operating leases, drilling rig commitments, volume commitment agreements and fracturing service agreements.

(2) See Note 8 to our audited consolidated financial statements for a description of our senior unsecured notes and related interest payments. As of December 31, 2011, we had no borrowings outstanding under our Amended Credit Facility.

(3) Amounts represent our estimate of future asset retirement obligations on an undiscounted basis. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 9 to our audited consolidated financial statements.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our audited consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other

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assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See Note 2 to our audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base (partial field) are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate for an entire field, in which case a gain or loss is recognized currently. Gains or losses from the disposal of properties are recognized currently.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated unproved lease acquisition costs. The expensing of the unproved lease acquisition costs is recorded as impairment expense in the statement of operations in our consolidated financial statements. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent reserve engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the SEC rules allow us to disclose proved, probable and possible reserves, we have elected to disclose only proved reserves in this Annual Report on Form 10-K. The SEC s rules define proved reserves as the quantities of oil and 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 that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Our independent reserve engineers and technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of 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.

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Periodic revisions to the estimated reserves and related future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Revenue recognition

Revenue from our interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. Substantially all of our production is sold to purchasers under short-term (less than 12 month) contracts at market-based prices. The sales prices for oil and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment.

Subsequently, these revenue deductions are adjusted to reflect actual charges based on third-party documents. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations. As a result, we maintain a minimum amount of product inventory in storage.

Impairment of proved properties

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected undiscounted future cash flows of our oil and natural gas properties and compare such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded.

Impairment of unproved properties

We assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage and record impairment expense for any decline in value.

We have historically recognized impairment expense for unproved properties at the time when the lease term has expired or sooner if, in management s judgment, the unproved properties have lost some or all of their carrying value. We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;
- our ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and

our evaluation of the continuing successful results from the application of completion technology in the Bakken formation by us or by other operators in areas adjacent to or near our unproved properties.

The assessment of unproved properties to determine any possible impairment requires significant judgment.

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Capitalized interest

We capitalize a portion of our interest expense incurred on our outstanding debt. The amount capitalized is determined by multiplying the capitalization rate by the average amount of eligible accumulated capital expenditures and is limited to actual interest costs incurred during the period. The accumulated capital expenditures included in the capitalization of interest calculation begin when the first costs are incurred and end when the asset is either placed into production or written off. Amounts capitalized are amortized over the life of the related assets.

Asset retirement obligations

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The asset retirement obligation (ARO) represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized cost is depreciated on the unit-of-production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in our Consolidated Statement of Operations.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Cash equivalents and short-term investments

We invest in certain money market funds, commercial paper and time deposits, all of which are stated at fair value or cost which approximates fair value due to the short-term maturity of these investments. We classify all such investments with original maturity dates less than 90 days as cash equivalents. We classify all such investments with original maturity dates greater than 90 days as held-to-maturity securities based on management s intentions to hold the investments to their maturity date.

Derivatives

We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivative instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. Realized gains and losses from the settlement of commodity derivative instruments and unrealized gains and losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under other income (expense) in our Consolidated Statement of Operations. The Company s cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements are reflected as investing activities in our Consolidated Statement of Cash Flows.

Stock-based compensation

Restricted stock awards. We recognize compensation expense for all restricted stock awards made to employees and directors. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the value of our common stock on the date of grant. Assumptions regarding forfeiture rates are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized. Stock-based compensation expense recorded for restricted stock awards is included in general and administrative expenses on our Consolidated Statement of Operations.

Class C common unit interests. In March 2010, we recorded a $5.2 million stock-based compensation charge associated with OP Management granting 1.0 million C Units to certain of our employees. The C Units were granted on March 24, 2010 to individuals who were employed as of February 1, 2010 and who were not executive officers or key employees with an

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existing capital investment in OP Management, or OP Management Capital Members. All of the C Units vested immediately on the grant date. Based on the characteristics of the C Units awarded to employees, we concluded that the C Units represented an equity-type award and accounted for the value of this award as if it had been awarded by us. The C Units were membership interests in OP Management and not a direct interest in us. The C Units are non-transferable and have no voting power. As of December 31, 2010, OP Management had distributed substantially all cash or requisite common stock to its members based on membership interests and distribution percentages.

In accordance with the Financial Accounting Standards Board s (FASB) authoritative guidance for share-based payments, we used a fair-value-based method to determine the value of stock-based compensation awarded to our employees and recognized the entire grant date fair value of $5.2 million as stock-based compensation expense due to the immediate vesting of the awards with no future requisite service period required of the employees. We used a probability weighted expected return method to evaluate the potential return and associated fair value allocable to the C Unit shareholders using selected hypothetical future outcomes (continuing operations, private sale and an initial public offering). Approximately 95% of the fair value allocable to the C Unit holders came from the IPO scenario.

The IPO fair value of the C Units awarded to our employees was estimated on the date of the grant using the Black-Scholes option-pricing model. The exercise price of the option used in the option-pricing model was set equal to the maximum value of OP Management s current capital investment in Oasis as that value had to be returned to OP Management Capital Members before distributions were made to the C Unit shareholders. Since we were not a public entity on the grant date, we did not have historical stock trading data to be used to compute volatilities associated with certain expected terms so the expected volatility value of 60% was estimated based on an average of volatilities of similar sized oil and gas companies with operations in the Williston Basin whose common stocks were publicly traded. The allocable fair value to the C Units assumed an estimated timing of four years based on a future potential secondary offering or distribution of common stock of Oasis. The 2.08% risk-free rate used in the pricing model was based on the U.S. Treasury yield for a government bond with a maturity equal to the time to liquidity of four years. We did not estimate forfeiture rates due to the immediate vesting of the award and did not estimate future dividend payments as we did not expect to declare or pay dividends in the foreseeable future.

Discretionary stock awards. During the fourth quarter of 2010, we recorded a $3.5 million stock-based compensation charge primarily associated with OP Management s grant of discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors. Based on the characteristics of these awards, we concluded that they represented an equity-type award and accounted for the value of these awards as if they had been awarded by us. The fair value of these awards was based on the value of our common stock on the date of grant. All of these awards vested immediately on the grant date with no future requisite service period required of the employees and contractors and were non-dilutive to us.

Treasury stock

Treasury stock shares represent shares withheld by us equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards. We include the withheld shares as treasury stock on our Consolidated Balance Sheet and separately pay the payroll tax obligation. These retained shares are not part of a publicly announced program to repurchase shares of our common stock and are accounted for at cost. We do not have a publicly announced program to repurchase shares of our common stock.

Income taxes

Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

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We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. We did not have uncertain tax positions outstanding and, as such, did not record a liability for the year ended December 31, 2011.

Recent accounting pronouncements

Fair value. In May 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 changes some fair value measurement principles under U.S. GAAP, including a change in the valuation premise and the application of premiums and discounts. It also contains some new disclosure requirements under U.S. GAAP. It is effective for interim and annual periods beginning after December 15, 2011. We do not expect the adoption of this new guidance to have a significant impact on our financial position, cash flows or results of operations.

Comprehensive income. In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05), which requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The new standard also requires presentation of adjustments for items that are reclassified from other comprehensive income to net income in the statement where the components of net income and the components of other comprehensive income are presented. The new standard does not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. In December 2011, the FASB issued ASU No. 2011-12, Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU 2011-12). ASU 2011-12 defers the specific requirement to present items that are reclassified from accumulated other comprehensive income to net income separately with their respective components of net income and other comprehensive income. ASU 2011-05 and ASU 2011-12 are effective for interim and annual periods beginning after December 15, 2011 and will be applied retrospectively. We do not expect the adoption of this new guidance to have any impact on our financial position, cash flows or results of operations.

Offsetting assets and liabilities. In December 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11), which requires entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting arrangement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. ASU 2011-11 is effective for interim and annual periods beginning on or after January 1, 2013. We do not expect the adoption of this new guidance to have any impact on our financial position, cash flows or results of operations.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2011, 2010 and 2009. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

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Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See Obligations and commitments above and Note 14 to our audited consolidated financial statements for a description of our commitments and contingencies.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity price exposure risk. We are exposed to market risk as the prices of oil and natural gas fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative instruments in the past and expect to enter into derivative instruments in the future to cover a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2011, we utilized two-way and three-way collar options and deferred premium puts to reduce the volatility of oil prices on a significant portion of our future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be WTI plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. For the deferred premium puts, we agree to pay a premium to the counterparty at the time of settlement. At settlement, if the WTI price is below the floor price of the put, we receive the difference between the floor price and the WTI price multiplied by the contract volumes less the premium. If the WTI price settles at or above the floor price of the put, we pay only the premium.

We recognize all derivative instruments at fair value; however, certain of our derivative instruments have a deferred premium put option, which reduces the asset or increases the liability, depending on the fair value of the derivative instrument. The credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet. Derivative assets and liabilities arising from our derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement.

The following is a summary of our derivative contracts as of December 31, 2011:

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Average Sub-Floor Price	Average Floor Price	Average Ceiling Price	Average Deferred Premium	Fair Value Asset (Liability) (In thousands)
2012	Two-Way Collars	1,756,718		$ 85.49	$ 106.44		$ (3,116)
2012	Three-Way Collars	2,906,500	$ 65.36	$ 89.97	$ 108.24		(2,046)
2012	Deferred Puts	641,000	$ 72.61	$ 92.61		$ 6.10	(745)
2013	Two-Way Collars	807,500		$ 89.23	$ 111.69		2,326
2013	Three-Way Collars	1,887,000	$ 70.19	$ 90.84	$ 112.60		(1,612)
2013	Deferred Puts	93,000	$ 71.67	$ 91.67		$ 6.33	(33)
2014	Two-Way Collars	62,000		$ 90.00	$ 112.78		289
2014	Three-Way Collars	155,000	$ 71.00	$ 91.00	$ 113.04		(113)
							$ (5,050)

Interest rate risk. At December 31, 2011, we had $400.0 million of senior unsecured notes at a fixed cash interest rate of 7.25% per annum and $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum outstanding at December 31, 2011. During the year ended December 31, 2011, we had no indebtedness outstanding under our revolving credit facility. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issued under our revolving credit facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

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Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. However, in order to mitigate the risk of nonperformance, we only enter into derivative contracts with counterparties that are high credit-quality financial institutions, all of which are lenders under our revolving credit facility. This risk is also managed by spreading our derivative exposure across several institutions and limiting the hedged volumes placed under individual contracts.

While we do not require all of our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty s credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, the financial ability of the customer s parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. Several of our significant customers for oil and natural gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we have considered the lack of investment grade credit rating in addition to the other factors described above.

As permitted under our investments policy, we may purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial sector. This risk is managed by our investment policy including minimum credit ratings thresholds and maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers failing to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If an issuer fails to repay us at maturity from commercial paper proceeds, it could take a significant amount of time to recover a portion of or all of the assets originally invested. Our commercial paper balance was $100.0 million at December 31, 2011.

The counterparties on our derivative instruments currently in place are lenders under our revolving credit facility with investment grade ratings. We are likely to enter into any future derivative instruments with these or other lenders under our revolving credit facility, which also carry investment grade ratings. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative asset position of $4.4 million and a net derivative liability position of $9.4 million at December 31, 2011.

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Item 8. Financial Statements and Supplementary Data

Index to Financial Statements

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Oasis Petroleum Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in stockholders /members equity and of cash flows present fairly, in all material respects, the financial position of Oasis Petroleum Inc. and its subsidiaries (the Company) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our audits (which was an integrated audit in 2011). 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

Houston, Texas

February 28, 2012

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Oasis Petroleum Inc.

Consolidated Balance Sheet

	September 30, December 31, 2011	September 30, 2010
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 470,872	$ 143,520
Short-term investments	19,994	
Accounts receivable oil and gas revenues	52,164	25,909
Accounts receivable joint interest partners	67,268	28,596
Inventory	3,543	1,323
Prepaid expenses	2,140	490
Advances to joint interest partners	3,935	3,595
Deferred income taxes	3,233	2,470
Other current assets	491	
Total current assets	623,640	205,903
Property, plant and equipment		
Oil and gas properties (successful efforts method)	1,235,357	580,968
Other property and equipment	20,859	1,970
Less: accumulated depreciation, depletion, amortization and impairment	(176,261)	(99,255)
Total property, plant and equipment, net	1,079,955	483,683
Derivative instruments	4,362	
Deferred costs and other assets	19,425	2,266
Total assets	$ 1,727,382	$ 691,852
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 12,207	$ 8,198
Advances from joint interest partners	9,064	3,101
Revenues and production taxes payable	19,468	6,180
Accrued liabilities	119,692	58,239
Accrued interest payable	15,774	2
Derivative instruments	5,907	6,543
Other current liabilities	472	
Total current liabilities	182,584	82,263
Long-term debt	800,000	
Asset retirement obligations	13,075	7,640
Derivative instruments	3,505	3,943
Deferred income taxes	92,983	45,432
Other liabilities	997	780
Total liabilities	1,093,144	140,058

Commitments and contingencies (Note 14)				
Stockholders equity				
Common stock, $0.01 par value; 300,000,000 shares authorized; 92,483,393 issued and 92,460,914 outstanding at December 31, 2011 and 92,240,345 shares issued and outstanding at December 31, 2010		921		920
Treasury stock, at cost; 22,479 shares		(602)		
Additional paid-in-capital		647,374		643,719
Retained deficit		(13,455)		(92,845)
Total stockholders equity		634,238		551,794
Total liabilities and stockholders equity	$	1,727,382	$	691,852

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

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Oasis Petroleum Inc.

Consolidated Statement of Operations

	September 30, 2011	September 30, 2010	September 30, 2009
	Year Ended December 31,		
	(In thousands, except per share data)		
Oil and gas revenues	$ 330,422	$ 128,927	$ 37,755
Expenses			
Lease operating expenses	34,072	14,582	8,691
Production taxes	33,865	13,768	3,810
Depreciation, depletion and amortization	74,981	37,832	16,670
Exploration expenses	1,685	297	1,019
Rig termination			3,000
Impairment of oil and gas properties	3,610	11,967	6,233
Loss (gain) on sale of properties	207		(1,455)
Stock-based compensation expenses		8,743	
General and administrative expenses	29,435	19,745	9,342
Total expenses	177,855	106,934	47,310
Operating income (loss)	152,567	21,993	(9,555)
Other income (expense)			
Net gain (loss) on derivative instruments	1,595	(7,653)	(4,747)
Interest expense	(29,618)	(1,357)	(912)
Other income (expense)	1,635	284	5
Total other income (expense)	(26,388)	(8,726)	(5,654)
Income (loss) before income taxes	126,179	13,267	(15,209)
Income tax expense	46,789	42,962	
Net income (loss)	$ 79,390	$ (29,695)	$ (15,209)
Earnings (loss) per share:			
Basic and diluted (Note 12)	$ 0.86	$ (0.61)	$
Weighted average shares outstanding:			
Basic (Note 12)	92,056	48,395	
Diluted (Note 12)	92,241	48,395	

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

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Oasis Petroleum Inc.

Consolidated Statement of Changes in Stockholders /Members Equity

(In thousands)

	September 30, Common Stock Number of Shares	September 30, Common Stock Amount	September 30, Treasury Stock Number of Shares	September 30, Treasury Stock Amount	September 30, Capital Contributions	September 30, Additional Paid-in-Capital	September 30, Retained Deficit/ Accumulated Loss	September 30, Total Stockholders / Members Equity
Balance as of December 31, 2008		$		$	$ 130,400	$	$ (47,941)	$ 82,459
Capital contributions					104,600			104,600
Net loss							(15,209)	(15,209)
Balance as of December 31, 2009					235,000		(63,150)	171,850
Issuance of common stock	92,000	920						920
Proceeds from the sale of common stock						398,749		398,749
Reclassification of members contributions					(235,000)	235,000		
Stock-based compensation	240					9,970		9,970
Net loss							(29,695)	(29,695)
Balance as of December 31, 2010	92,240	920				643,719	(92,845)	551,794
Stock-based compensation	243					3,656		3,656
Vesting of restricted shares		1				(1)		
Treasury stock tax withholdings	(22)		22	(602)				(602)
Net income							79,390	79,390
Balance as of December 31, 2011	92,461	$ 921	22	$ (602)	$	$ 647,374	$ (13,455)	$ 634,238

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

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Oasis Petroleum Inc.

Consolidated Statement of Cash Flows

	September 30, 2011	September 30, December 31, 2010	September 30, 2009
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 79,390	$ (29,695)	$ (15,209)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	74,981	37,832	16,670
Impairment of oil and gas properties	3,610	11,967	6,233
Loss (gain) on sale of properties	207		(1,455)
Deferred income taxes	46,789	42,962	
Derivative instruments	(1,595)	7,653	4,747
Stock-based compensation expenses	3,656	9,970	
Debt discount amortization and other	1,561	470	95
Working capital and other changes:			
Change in accounts receivable	(64,900)	(44,450)	(6,409)
Change in inventory	(2,550)	(498)	(218)
Change in prepaid expenses	(1,600)	(356)	(40)
Change in other current assets	(491)		
Change in other assets	(139)	(164)	(667)
Change in accounts payable and accrued liabilities	36,316	13,917	2,440
Change in other current liabilities	472		
Change in other liabilities	317	4	(39)
Net cash provided by operating activities	176,024	49,612	6,148
Cash flows from investing activities:			
Capital expenditures	(613,223)	(226,544)	(47,396)
Acquisition of oil and gas properties		(86,393)	(35,215)
Derivative settlements	(3,841)	(120)	2,296
Purchases of short-term investments	(184,907)		
Redemptions of short-term investments	164,913		
Advances to joint interest partners	(497)	1,010	(2,331)
Advances from joint interest partners	5,963	2,512	383
Proceeds from equipment and property sales	2,202		1,507
Net cash used in investing activities	(629,390)	(309,535)	(80,756)
Cash flows from financing activities:			
Proceeds from members contributions			104,600
Proceeds from sale of common stock		399,669	
Proceeds from credit facility		72,000	22,000
Principal payments on credit facility		(107,000)	(13,000)
Proceeds from issuance of senior notes	800,000		
Purchases of treasury stock	(602)		
Debt issuance costs	(18,680)	(1,788)	
Net cash provided by financing activities	780,718	362,881	113,600

Increase in cash and cash equivalents		327,352		102,958		38,992
Cash and cash equivalents:						
Beginning of period		143,520		40,562		1,570
End of period	$	470,872	$	143,520	$	40,562
Supplemental cash flow information:						
Cash interest paid, net of capitalized interest	$	13,748	$	1,002	$	674
Supplemental non-cash transactions:						
Change in accrued capital expenditures	$	58,205	$	35,181	$	4,134
Change in asset retirement obligations		5,434		1,227		2,156

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

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements

1. Organization and Operations of the Company

Organization

Oasis Petroleum Inc. (Oasis or the Company) was formed on February 25, 2010, pursuant to the laws of the State of Delaware, to become a publicly traded entity. The Company s predecessor, Oasis Petroleum LLC (OP LLC), was formed as a Delaware limited liability company on February 26, 2007 by certain members of the Company s senior management team and through investments made by Oasis Petroleum Management LLC (OP Management) and certain private equity funds managed by EnCap Investments L.P. (EnCap). OP Management, a Delaware limited liability company, was formed in February 2007 to allow Company employees to become indirect investors in OP LLC. In May 2007, the Company formed Oasis Petroleum North America LLC (OPNA), a Delaware limited liability company, to conduct its domestic oil and natural gas exploration and production activities. In April 2008, the Company formed Oasis Petroleum International LLC (OPI), a Delaware limited liability company, to conduct business development activities outside of the United States of America. In June 2011, the Company formed Oasis Well Services LLC (OWS), a Delaware limited liability company, to provide well services to OPNA. In July 2011, the Company formed Oasis Petroleum Marketing LLC (OPM), a Delaware limited liability company, to provide marketing services to OPNA. As of December 31, 2011, OWS, OPM and OPI had no material business activities or material assets.

A corporate reorganization occurred concurrently with the completion of the Company s initial public offering (IPO) of its common stock on June 22, 2010. The Company sold 30,370,000 shares and OAS Holding Company LLC (OAS Holdco), the selling stockholder, sold 17,930,000 shares of the Company s common stock, in each case, at $14.00 per share. After deducting underwriting discounts and commissions of approximately $25.5 million, the Company received net proceeds of $399.7 million. The selling stockholder received aggregate net proceeds of approximately $236.0 million. The Company did not receive any proceeds from the sale of the shares by OAS Holdco. As a part of this corporate reorganization, the Company acquired all of the outstanding membership interests in OP LLC in exchange for shares of the Company s common stock. The Company s business continues to be conducted through OP LLC, as a wholly owned subsidiary.

Nature of Business

The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources primarily in the Williston Basin. The Company s assets, which consist of proved and unproved oil and natural gas properties, are located primarily in the Montana and North Dakota areas of the Williston Basin and are owned by OPNA.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements of the Company include the accounts of Oasis and its wholly owned subsidiaries: OP LLC, OPNA, OPI, OWS and OPM. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). All significant intercompany transactions have been eliminated in consolidation. Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income (loss).

Use of Estimates

Preparation of the Company s consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in impairment tests of long-lived assets, estimates of future development, dismantlement and abandonment costs, estimates relating to certain oil and natural gas revenues and expenses and estimates of expenses related to legal, environmental and other contingencies. Certain of these estimates require assumptions regarding future commodity prices, future costs and expenses and future production rates. Actual results could differ from those estimates.

As an oil and natural gas producer, the Company s revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, political and regulatory developments and competition from other energy sources. The energy markets have historically been very volatile and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and natural gas prices could have a material adverse effect on the Company s financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.

Estimates of oil and natural gas reserves and their values, future production rates and future costs and expenses are inherently uncertain for numerous reasons, including many factors beyond the Company s control. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, prevailing commodity prices, operating costs and other factors. These revisions may be material and could materially affect future depletion, depreciation and amortization expense, dismantlement and abandonment costs, and impairment expense.

Cash Equivalents and Short-Term Investments

The Company invests in certain money market funds, commercial paper and time deposits, all of which are stated at fair value or cost which approximates fair value due to the short-term maturity of these investments. The Company classifies all such investments with original maturity dates less than 90 days as cash equivalents. The Company classifies all such investments with original maturity dates greater than 90 days as held-to-maturity securities based on management s intentions to hold the investments to their maturity dates.

Accounts Receivable

Accounts receivable are carried on a gross basis, with no discounting. The Company regularly reviews all aged accounts receivable for collectability and establishes an allowance as necessary for individual customer balances. No allowance for doubtful accounts was recorded for the years ended December 31, 2011 and 2010.

Inventory

Equipment and materials consist primarily of tubular goods and well equipment to be used in future drilling or ongoing operations and are stated at the lower of cost or market with cost determined on an average cost method. Crude oil inventories are valued at the lower of average cost or market value. Inventory consists of the following:

	September 30, December 31, 2011	September 30, 2010
	(In thousands)	
Equipment and materials	$ 2,709	$ 640
Crude oil inventory	834	683
	$ 3,543	$ 1,323

Joint Interest Partner Advances

The Company participates in the drilling of oil and natural gas wells with other working interest partners. Due to the capital intensive nature of oil and natural gas drilling activities, the working interest partner responsible for conducting the drilling operations may request advance payments from other working interest partners for their share of the costs. The Company expects such advances to be applied by working interest partners against joint interest billings for its share of drilling operations within 90 days from when the advance is paid.

Property, Plant and Equipment

Proved Oil and Gas Properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively.

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The provision for depreciation, depletion and amortization (DD&A) of oil and natural gas properties is calculated on a field-by-field basis using the unit-of-production method. Natural gas is converted to barrel equivalents at the rate of six thousand cubic feet of natural gas to one barrel of oil. The calculation for the unit-of-production DD&A method takes into consideration estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base (partial field) are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate for an entire field, in which case a gain or loss is recognized currently. In December 2009, the Company sold its interests in non-core oil and natural gas producing properties located in the Barnett shale in Texas for an aggregate $1.5 million in cash. The Company recognized a gain of $1.4 million from the sale of these divested properties. In November 2011, the Company sold its remaining interests in non-core oil and natural gas producing properties located in the Barnett shale in Texas and interests in certain properties for an aggregate $2.2 million in cash. The Company recognized a loss of $0.2 million from these divestures. No gain or loss for the sale of oil and natural gas properties was recorded for the year ended December 31, 2010.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and natural gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to management s judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs, as further discussed in Note 3 Fair Value Measurements. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2011 and 2010. During the year ended December 31, 2009, the Company recorded a $0.8 million non-cash impairment charge on its proved oil and natural gas properties.

Unproved Oil and Gas Properties

Unproved properties consist of costs incurred to acquire unproved leases (lease acquisition costs). Lease acquisition costs are capitalized until the leases expire or when the Company specifically identifies leases that will revert to the lessor, at which time the Company expenses the associated lease acquisition costs. The expensing of the lease acquisition costs is recorded as Impairment of oil and gas properties in the Consolidated Statement of Operations. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

The Company assesses its unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage and records impairment expense for any decline in value. As a result of expiring unproved property leases, the Company recorded non-cash impairment charges of $3.6 million, $12.0 million and $5.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Capitalized Interest

The Company capitalizes a portion of its interest expense incurred on its outstanding debt. The amount capitalized is determined by multiplying the capitalization rate by the average amount of eligible accumulated capital expenditures and is limited to actual interest costs incurred during the period. The accumulated capital expenditures included in the capitalization of interest calculation begin when the first costs are incurred and end when the asset is either placed into production or written off. The Company capitalized $3.1 million of interest costs for the year ended December 31, 2011. This amount will be amortized over the life of the related assets. No interest costs were capitalized for the years ended December 31, 2010 and 2009.

Other Property and Equipment

Furniture, equipment and leasehold improvements are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets. The Company uses estimated lives of three to five years for these types of assets. The cost of assets disposed of and the associated accumulated depletion, depreciation and amortization are removed from the Company s Consolidated Balance Sheet with any gain or loss realized upon the sale or disposal included in the Company s Consolidated Statement of Operations.

Exploration Expenses

Exploration costs, including certain geological and geophysical expenses and the costs of carrying and retaining undeveloped acreage, are charged to expense as incurred.

Costs from drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful. Determination is usually made on or shortly after drilling or completing the well, however, in certain situations a determination cannot be made when drilling is completed. The Company defers capitalized exploratory drilling costs for wells that have found a sufficient quantity of producible hydrocarbons but cannot be classified as proved because they are located in areas that require major capital expenditures or governmental or other regulatory approvals before production can begin. These costs continue to be deferred as wells-in-progress as long as development is underway, is firmly planned for the near future or the necessary approvals are actively being sought.

Net changes in capitalized exploratory well costs are reflected in the following table for the periods presented:

	September 30, 2011	September 30, December 31, 2010	September 30, 2009
		(In thousands)	
Beginning of period	$ 5,176	$ 427	$ 324
Exploratory well cost additions (pending determination of proved reserves)	73,947	39,708	72,972
Exploratory well cost reclassifications (successful determination of proved reserves)	(57,646)	(34,959)	(72,869)
Exploratory well dry hole costs (unsuccessful in adding proved reserves)	(1,270)		
End of period	$ 20,207	$ 5,176	$ 427

As of December 31, 2011, the Company had no exploratory well costs that were capitalized for a period greater than one year.

Deferred Costs

The Company capitalizes costs incurred in connection with obtaining financing. These costs are included in Deferred costs and other assets on the Company s Consolidated Balance Sheet and are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method.

Asset Retirement Obligations

In accordance with the Financial Accounting Standard Board s (FASB) authoritative guidance on asset retirement obligations (ARO), the Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The ARO represents the estimated amount the Company will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized costs are depreciated using the unit-of-production method. The accretion expense is recorded as a component of Depreciation, depletion and amortization in the Company s Consolidated Statement of Operations.

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The Company determines the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs, as further discussed in Note 3 Fair Value Measurements. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Revenue Recognition

Revenue from the Company s interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. Substantially all of the Company s production is sold to purchasers under short-term (less than 12 months) contracts at market-based prices. The sales prices for oil and natural gas are adjusted for transportation and quality differentials. These differentials are based on contractual or historical data and do not require significant judgment. Subsequently, these revenue differentials are adjusted to reflect actual charges based on third-party documents. Since there is a ready market for oil and natural gas, the Company sells the majority of its production soon after it is produced at various locations. As a result, the Company maintains a minimum amount of product inventory in storage.

Revenues Payable and Production Taxes

The Company calculates and pays taxes and royalties on oil and natural gas in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements.

Concentrations of Market and Credit Risk

The future results of the Company s oil and natural gas operations will be affected by the market prices of oil and natural gas. The availability of a ready market for oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production sector of the oil and gas industry. The Company s receivables include amounts due from purchasers of its oil and natural gas production and amounts due from joint venture partners for their respective portions of operating expenses and exploration and development costs. While certain of these customers and joint venture partners are affected by periodic downturns in the economy in general or in their specific segment of the oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company s results of operations over the long-term. Trade receivables are generally not collateralized.

The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of temporary cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its customers is generally high. In the normal course of business, letters of credit or parent guarantees are required for counterparties which management perceives to have a higher credit risk.

Risk Management

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2011, the Company utilized two-way and three-way collar options and deferred premium puts to reduce the volatility of oil prices on a significant portion of the Company s future expected oil production (see Note 4 Derivative Instruments).

The Company records all derivative instruments on the Consolidated Balance Sheet as either assets or liabilities measured at their estimated fair value. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. Realized gains and losses from the settlement of commodity derivative instruments and unrealized gains and losses from valuation changes in the remaining unsettled commodity derivative instruments are reported in the Other income (expense) section of the Company s Consolidated Statement of Operations. Unrealized gains are included in current and noncurrent assets and unrealized losses are included in current and noncurrent liabilities on the Consolidated Balance Sheet, respectively. The Company s cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements are reflected as investing activities in the Company s Consolidated Statement of Cash Flows.

Derivative financial instruments that hedge the price of oil are executed with major financial institutions that expose the Company to market and credit risks and which may, at times, be concentrated with certain counterparties or groups of counterparties. The Company has derivatives in place with four counterparties, all of which are lenders under the Company s revolving credit facility. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk in the event of nonperformance by the counterparties are substantially smaller. The credit worthiness of the counterparties is subject to continual review. The Company believes the risk of nonperformance by its counterparties is low. Full performance is anticipated, and the Company has no past-due receivables from its counterparties. The Company s policy is to execute financial derivatives only with major, credit-worthy financial institutions.

The Company s derivative contracts are documented with industry standard contracts known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. Master Agreement (ISDA). Typical terms for the ISDAs include credit support requirements, cross default provisions, termination events and set-off provisions. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the properties securing the Company s revolving credit facility (see Note 8 Long-Term Debt). As of December 31, 2011, the Company had limitations under its revolving credit facility, including a provision limiting the total amount of production that may be hedged by the Company to 100% of Current Production (as defined in the revolving credit facility) for the period from 1 to 24 months after the date of each derivative. As of December 31, 2011, the Company was in compliance with these limitations as its contractual commodity derivative volumes for 2012 and 2013 represent a maximum within each year of approximately 96% and 46%, respectively, of its Current Production.

Environmental Costs

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and which do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

Restricted Stock Awards

The Company has granted restricted stock awards to employees and directors under its 2010 Long-Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the value of the Company s common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. As of December 31, 2011, the Company assumed no annual forfeiture rate because of the Company s lack of turnover and lack of forfeiture history for this type of award.

Any excess tax benefit arising from our stock-based compensation plan is recognized as a credit to additional paid-in-capital when realized and is calculated as the amount by which the tax deduction received exceeds the deferred tax asset associated with the recorded stock-based compensation expense. As of December 31, 2011, the excess tax deduction related to stock compensation is $0.8 million. Since the Company is in a net operating loss position for tax purposes, none of the excess tax deduction has been reflected in additional paid in capital. Pursuant to GAAP, the Company s deferred tax asset related to net operating carryforward is net of the unrealized tax benefit from stock-based compensation.

Treasury Stock

Treasury stock shares represent shares withheld by the Company equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards. The Company includes the withheld shares as Treasury stock on its Consolidated Balance Sheet and separately pays the payroll tax obligation. These retained shares are not part of a publicly announced program to repurchase shares of the Company s common stock and are accounted for at cost. The Company does not have a publicly announced program to repurchase shares of its common stock.

Income Taxes

The Company s provision for taxes includes both federal and state taxes. The Company records its federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company applies significant judgment in evaluating its tax positions and estimating its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

The Company also accounts for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not-threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. The Company does not have uncertain tax positions outstanding and, as such, did not record a liability for the year ended December 31, 2011.

Fair Value of Financial and Non-Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable, accounts payable and other payables approximate their respective fair market values due to their short-term maturities. The Company s derivative instruments and asset retirement obligations are also recorded on the Consolidated Balance Sheet at amounts which approximate fair market value. See Note 3 Fair Value Measurements.

Recent Accounting Pronouncements

Fair value. In May 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 changes some fair value measurement principles under GAAP, including a change in the valuation premise and the application of premiums and discounts. It also contains some new disclosure requirements under GAAP. It is effective for interim and annual periods beginning after December 15, 2011. The Company does not expect the adoption of this new guidance to have a significant impact on its financial position, cash flows or results of operations.

Comprehensive income. In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05), which requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The new standard also requires presentation of adjustments for items that are reclassified from other comprehensive income to net income in the statement where the components of net income and the components of other comprehensive income are presented. The new standard does not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. In December 2011, the FASB issued ASU No. 2011-12, Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of

Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU 2011-12). ASU 2011-12 defers the specific requirement to present items that are reclassified from accumulated other comprehensive income to net income separately with their respective components of net income and other comprehensive income. ASU 2011-05 and ASU 2011-12 are effective for interim and annual periods beginning after December 15, 2011 and will be applied retrospectively. The Company does not expect the adoption of this new guidance to have any impact on its financial position, cash flows or results of operations.

Offsetting assets and liabilities. In December 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11), which requires entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting arrangement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. ASU 2011-11 is effective for interim and annual periods beginning on or after January 1, 2013. The Company does not expect the adoption of this new guidance to have any impact on its financial position, cash flows or results of operations.

3. Fair Value Measurements

In accordance with FASB s authoritative guidance on fair value measurements, the Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company recognizes its non-financial assets and liabilities, such as asset retirement obligations and proved oil and natural gas properties upon impairment, at fair value on a non-recurring basis.

As defined in the authoritative guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The authoritative guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are as follows:

Level 1 Unadjusted quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Pricing inputs, other than unadjusted quoted prices in active markets included in Level 1, are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, 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. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 Pricing inputs are generally less observable from objective sources, requiring internally developed valuation methodologies that result in management s best estimate of fair value.

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As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis:

	September 30,		September 30,		September 30,		September 30,	
			At fair value as of December 31, 2011					
	Level 1		Level 2		Level 3		Total	
			(In thousands)					
Assets (liabilities):								
Money market funds	$	250,419	$		$		$	250,419
Commodity derivative instruments (see Note 4)						(5,050)		(5,050)
Total assets (liabilities)	$	250,419	$		$	(5,050)	$	245,369

			At fair value as of December 31, 2010					
	Level 1		Level 2		Level 3		Total	
			(In thousands)					
Assets (liabilities):								
Commodity derivative instruments (see Note 4)	$		$		$	(10,486)	$	(10,486)
Total assets (liabilities)	$		$		$	(10,486)	$	(10,486)

The Level 1 instruments presented in the table above consist of money market funds included in Cash and cash equivalents on the Company s Consolidated Balance Sheet at December 31, 2011. The Company s money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identified the money market funds at Level 1 instruments due to the fact that the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments.

The Level 3 instruments presented in the tables above consist of oil collars and deferred premium puts. The fair values of the Company s oil collars and deferred premium puts are based upon mark-to-market valuation reports provided by its counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has a third-party reviewer evaluate other readily available market prices for its derivative contracts as there is an active market for these contracts. However, the Company does not have access to the specific valuation models used by its counterparties or third party reviewer. The determination of the fair values presented above also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculated the credit adjustment for derivatives in an asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a liability position is based on the Company s current cost of prime based borrowings (prime rate and associated margin effect). Based on these calculations, the Company recorded a downward adjustment to the fair value of its derivative instruments in the amount of $0.3 million for each year ended December 31, 2011 and 2010.

The following table presents a reconciliation of the changes in fair value of the derivative instruments classified as Level 3 in the fair value hierarchy for the years presented.

	September 30, 2011		September 30, 2010		September 30, 2009	
			(In thousands)			
Balance as of January 1	$	(10,486)	$	(2,953)	$	4,090
Total gains or (losses) (realized or unrealized):						
Included in earnings		1,595		(7,653)		(4,747)
Included in other comprehensive income						
Purchases, issuances and settlements		3,841		120		(2,296)
Transfers in and out of Level 3						

Balance as of December 31	$	(5,050)	$	(10,486)	$	(2,953)
Change in unrealized gains (losses) included in earnings relating to derivatives still held at December 31	$	5,436	$	(7,533)	$	(7,043)

At December 31, 2011, the Company s financial instruments, including cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The carrying amount of the Company s long-term debt reported in the Consolidated Balance Sheet at December 31, 2011 is $800.0 million, with a fair value of $811.0 million. The carrying amount of the Company s ARO in the Consolidated Balance Sheet at December 31, 2011 is $13.1 million, which approximates fair value as the Company determines the ARO by calculating the present value of estimated cash flows related to the liability based on the calculation of the estimated value (see Note 2 Summary of Significant Accounting Policies).

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Therefore, the Company s proved oil and natural gas properties are measured at fair value on a non-recurring basis. No impairment charge on proved oil and natural gas properties was recorded for the years ended December 31, 2011 and 2010. During the year ended December 31, 2009, the Company recorded a $0.8 million non-cash impairment charge on its proved oil and natural gas properties, as further discussed in Note 2 Summary of Significant Accounting Policies. The 2009 impairment charge related to certain dry holes, which had a fair value of zero.

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4. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2011, the Company utilized two-way and three-way collar options and deferred premium puts to reduce the volatility of oil prices on a significant portion of the Company s future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX West Texas Intermediate (WTI) crude oil index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement. At settlement, if the WTI price is below the floor price of the put, the Company receives the difference between the floor price and the WTI price multiplied by the contract volumes less the premium. If the WTI price settles at or above the floor price of the put, the Company pays only the premium.

All derivative instruments are recorded on the Consolidated Balance Sheet as either assets or liabilities measured at their fair value (see Note 3 Fair Value Measurements). Derivative assets and liabilities arising from the Company s derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value, both realized and unrealized, are recognized in the Other income (expense) section of the Company s Consolidated Statement of Operations as a gain or loss on derivative instruments. The Company s cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements are reflected as investing activities in the Company s Consolidated Statement of Cash Flows.

As of December 31, 2011, the Company had the following outstanding commodity derivative contracts, all of which settle monthly based on the WTI crude oil index price, and none of which were designated as hedges:

	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,	September 30,
Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Average Sub-Floor Price	Average Floor Price	Average Ceiling Price	Average Deferred Premium	Fair Value Asset (Liability) (In thousands)
2012	Two-Way Collars	1,756,718		$ 85.49	$ 106.44		$ (3,116)
2012	Three-Way Collars	2,906,500	$ 65.36	$ 89.97	$ 108.24		(2,046)
2012	Deferred Puts	641,000	$ 72.61	$ 92.61		$ 6.10	(745)
2013	Two-Way Collars	807,500		$ 89.23	$ 111.69		2,326
2013	Three-Way Collars	1,887,000	$ 70.19	$ 90.84	$ 112.60		(1,612)
2013	Deferred Puts	93,000	$ 71.67	$ 91.67		$ 6.33	(33)
2014	Two-Way Collars	62,000		$ 90.00	$ 112.78		289
2014	Three-Way Collars	155,000	$ 71.00	$ 91.00	$ 113.04		(113)
							$ (5,050)

The following table summarizes the location and fair value of all outstanding commodity derivative contracts recorded in the balance sheet for the periods presented:

	September 30, Fair Value of Derivative Instrument Assets (Liabilities)	September 30,	September 30,
		Fair Value December 31, (In thousands)	
Instrument Type	Balance Sheet Location	2011	2010

Crude oil collar	Derivative instruments	non-current assets	$	4,362	$	
Crude oil collar	Derivative instruments	current liabilities		(5,907)		(6,543)
Crude oil collar	Derivative instruments	non-current liabilities		(3,505)		(3,943)
Total derivative instruments			$	(5,050)	$	(10,486)

The following table summarizes the location and amounts of realized and unrealized gains and losses from the Company s commodity derivative contracts for the periods presented:

	September 30, Income Statement Location	September 30, 2011	September 30, December 31, 2010 (In thousands)	September 30, 2009
Change in unrealized gain (loss) on derivative instruments	Net gain (loss) on derivative instruments	$ 5,436	$ (7,533)	$ (7,043)
Realized gain (loss) on derivative instruments	Net gain (loss) on derivative instruments	(3,841)	(120)	2,296
Total net gain (loss) on derivative instruments		$ 1,595	$ (7,653)	$ (4,747)

5. Property, Plant and Equipment

The following table sets forth the Company s property, plant and equipment:

	September 30, December 31, 2011	September 30, 2010
	(In thousands)	
Proved oil and gas properties	$ 1,152,532	$ 479,657
Less: Accumulated depreciation, depletion, amortization and impairment	(174,948)	(98,821)
Proved oil and gas properties, net	977,584	380,836
Unproved oil and gas properties	82,825	101,311
Other property and equipment	20,859	1,970
Less: Accumulated depreciation	(1,313)	(434)
Other property and equipment, net	19,546	1,536
Total property, plant and equipment, net	$ 1,079,955	$ 483,683

Included in the Company s oil and gas properties are asset retirement costs of $11.4 million and $6.3 million at December 31, 2011 and 2010, respectively.

Asset Impairments As discussed in Note 2, as a result of expiring unproved property leases, the Company recorded non-cash impairment charges on its unproved oil and gas properties of $3.6 million, $12.0 million and $5.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. For the year ended December 31, 2009, the Company also recorded a non-cash impairment charge of $0.8 million on its proved oil and gas properties. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2011 and 2010.

6. Acquisitions

Asset Acquisitions During the fourth quarter of 2010, the Company acquired approximately 16,700 net acres of land in Roosevelt County, Montana and approximately 10,000 net leasehold acres primarily located in Richland County, Montana for $52.3 million and $30.1 million, respectively. This acreage is part of our West Williston project area. Based on the FASB s relative authoritative guidance, neither acquisition qualified as a business combination. The Company did not have any significant asset acquisitions for the year ended December 31, 2011.

Kerogen Acquisition On June 15, 2009, the Company acquired interests in certain oil and gas properties primarily in the East Nesson area of the Williston Basin from Kerogen Resources, Inc. (the Kerogen Acquisition Properties) for $27.1 million. In addition to acquiring the interests in the East Nesson project area, the Company also acquired non-operated interests in the Sanish project area.

The Kerogen acquisition qualified as a business combination, and as such, the Company estimated the fair value of these properties as of the June 15, 2009 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed in Note 3 Fair Value Measurements.

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The Company estimated the fair value of the Kerogen Acquisition Properties to be approximately $27.1 million, which the Company considered to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. The acquisition related costs were insignificant.

The following table summarizes the consideration paid for the Kerogen Acquisition Properties and the fair value of the assets acquired and liabilities assumed as of June 15, 2009.

		September 30,
Consideration given to Kerogen Resources, Inc. (in thousands):		
Cash	$	27,087
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed properties	$	25,178
Proved undeveloped properties		1,647
Unproved lease acquisition costs		360
Seismic costs		667
Asset retirement obligations		(765)
Total identifiable net assets	$	27,087

Summarized below are the consolidated results of operations for the year ended December 31, 2009, on an unaudited pro forma basis, as if the acquisition had occurred on January 1 of that year. The unaudited pro forma financial information was derived from the historical consolidated statement of operations of the Company and the statement of revenues and direct operating expenses for the Kerogen Acquisition Properties, which were derived from the historical accounting records of the seller. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of the Company s expected future results of operations.

	September 30,		September 30,	
	Year Ended December 31, 2009			
	Actual		Pro Forma	
	(In thousands) Unaudited			
Kerogen Acquisition Properties:				
Revenues	$	37,755	$	41,999
Net Loss	$	(15,209)	$	(15,461)

Fidelity Acquisition On September 30, 2009, the Company acquired additional interests in the East Nesson project area of the Williston Basin from Fidelity Exploration and Production Company (the Fidelity Acquisition Properties) for $10.7 million.

The Fidelity acquisition qualified as a business combination, and as such, the Company estimated the fair value of these properties as of the September 30, 2009 acquisition date. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed in Note 3 Fair Value Measurements.

The Company estimated the fair value of the Fidelity Acquisition Properties to be approximately $10.7 million, which the Company considered to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. The acquisition related costs were insignificant.

The following table summarizes the consideration paid for the Fidelity Acquisition Properties and the fair value of the assets acquired and liabilities assumed as of September 30, 2009.

		September 30,
Consideration given to Fidelity Exploration and Production Company (in thousands):		
Cash	$	10,681
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed properties	$	4,668
Proved undeveloped properties		2,415
Unproved lease acquisition costs		3,450
Seismic costs		667
Asset retirement obligations		(519)
Total identifiable net assets	$	10,681

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Summarized below are the consolidated results of operations for the year ended December 31, 2009, on an unaudited pro forma basis as if the acquisition had occurred on January 1 of that year. The pro forma financial information was derived from the historical consolidated statement of operations of the Company and the statement of revenues and direct operating expenses for the Fidelity Acquisition Properties, which were derived from the historical accounting records of the seller. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of the Company s expected future results of operations.

	September 30,	September 30,
	Year Ended December 31, 2009	
	Actual	Pro Forma
	(In thousands) Unaudited	
Fidelity Acquisition Properties:		
Revenues	$ 37,755	$ 40,934
Net Loss	$ (15,209)	$ (15,872)

7. Accrued Liabilities

The Company s accrued liabilities consist of the following:

	September 30,	September 30,
	December 31,	
	2011	2010
	(In thousands)	
Accrued capital costs	$ 106,405	$ 49,935
Accrued lease operating expenses	7,794	3,305
Accrued general and administrative expenses	3,397	3,014
Other accrued liabilities	2,096	1,985
Total accrued liabilities	$ 119,692	$ 58,239

In addition, the Company had revenue suspense of $9.5 million, production taxes payable of $5.7 million and royalties payable of $3.2 million included in Revenues and production taxes payable on the Consolidated Balance Sheet for the year ended December 31, 2011. For the year ended December 31, 2010, the Company had $3.2 million of production taxes payable, $2.3 million of revenue suspense and $0.3 million of royalties payable included in Revenues and production taxes payable on the Consolidated Balance Sheet.

8. Long-Term Debt

Senior Secured Revolving Line of Credit OP LLC, as parent, and OPNA, as borrower, entered into a credit agreement dated June 22, 2007 (as amended and restated, the Amended Credit Facility). The Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On October 6, 2011, the Company entered into its fifth amendment to its Amended Credit Facility. This amendment reduced the interest rates payable on the borrowings under the Amended Credit Facility, extended the maturity date of the Amended Credit Facility from February 26, 2015 to October 6, 2016, and increased the senior secured revolving line of credit from $600 million to $1 billion. In connection with this amendment, the semi-annual redetermination of the borrowing base was also completed on October 6, 2011, which resulted in the borrowing base of the Amended Credit Facility increasing from $137.5 million to $350 million. In addition, on October 25, 2011, the Company s lenders in the Amended Credit Facility waived the mandatory reduction of the Company s borrowing base that otherwise would have occurred as a result of the issuance of the senior unsecured notes subsequently offered (see Senior Unsecured 2021 Notes below). Borrowings under the Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company s assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports.

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Borrowings under the Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate (LIBOR) loan or a domestic bank prime interest rate loan (defined in the Amended Credit Facility as an Alternate Based Rate or ABR loan). As of December 31, 2011, any outstanding LIBOR and ABR loans would have beared their respective interest rates plus the applicable margin indicated in the following table:

Ratio of Total Outstanding Borrowings to Borrowing Base	September 30, Applicable Margin for LIBOR Loans	September 30, Applicable Margin for ABR Loans
Less than .25 to 1	1.50%	0.00%
Greater than or equal to .25 to 1 but less than .50 to 1	1.75%	0.25%
Greater than or equal to .50 to 1 but less than .75 to 1	2.00%	0.50%
Greater than or equal to .75 to 1 but less than .90 to 1	2.25%	0.75%
Greater than .90 to 1 but less than or equal 1	2.50%	1.00%

An ABR loan may be repaid at any time before the scheduled maturity of the Amended Credit Facility upon the Company providing advance notification to the lenders under the Amended Credit Facility (the Lenders). Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. The Company has the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the Lenders. The minimum available loan term is one month and the maximum loan term is six months for LIBOR-based loans. Interest for LIBOR loans is paid upon maturity of the loan term. Interim interest is paid every three months for LIBOR loans that have loan terms greater than three months in duration. At the end of a LIBOR loan term, the Amended Credit Facility allows the Company to elect to repay the borrowing, continue a LIBOR loan with the same or a differing loan term or convert the borrowing to an ABR loan.

On a quarterly basis, the Company also pays a 0.375% (as of December 31, 2011) annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

The Amended Credit Facility contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;
- a prohibition against making investments, loans and advances, subject to permitted exceptions;
- restrictions on creating liens and leases on the assets of the Company and its subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;
- a provision limiting oil and natural gas derivative financial instruments;

- a requirement that the Company not allow a ratio of Total Net Debt (as defined in the Amended Credit Facility) to consolidated EBITDAX (as defined in the Amended Credit Facility) to be greater than 4.0 to 1.0 for the four quarters ended on the last day of each quarter; and

- a requirement that the Company maintain a Current Ratio (as defined in the Amended Credit Facility) of consolidated current assets (with exclusions as described in the Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Amended Credit Facility) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The Amended Credit Facility contains customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under the Amended Credit Facility to be immediately due and payable.

As of December 31, 2011, the Company had no borrowings and no outstanding letters of credit issued under the Amended Credit Facility, resulting in an unused borrowing base capacity of $350 million. The Company was in compliance with the financial covenants of the Amended Credit Facility as of December 31, 2011.

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Senior Unsecured 2019 Notes On February 2, 2011, the Company issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the 2019 Notes). Interest on the 2019 Notes is payable semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The 2019 Notes are guaranteed on a senior unsecured basis by the Company s material subsidiaries (the Guarantors). These guarantees are full and unconditional and joint and several among the Guarantors. The issuance of these 2019 Notes resulted in net proceeds to the Company of approximately $390.0 million.

The 2019 Notes were issued under an indenture, dated as of February 2, 2011 (the 2019 Base Indenture), among the Company and U.S. Bank National Association, as trustee (the Trustee), as amended and supplemented by the first supplemental indenture among the Company, the Guarantors and the Trustee, also dated as of February 2, 2011 (the 2019 First Supplemental Indenture) and as further amended and supplemented by the second supplemental indenture among the Company, the Guarantors and the Trustee (the 2019 Second Supplemental Indenture ; the 2019 Base Indenture, as amended and supplemented by the 2019 First Supplemental Indenture and the 2019 Second Supplemental Indenture, the 2019 Indenture), dated as of September 19, 2011. On September 23, 2011, the Company filed a Registration Statement on Form S-4 (Registration No. 333-176974) with the Securities and Exchange Commission (SEC) to allow the holders of the 2019 Notes to exchange the 2019 Notes for registered notes that have substantially identical terms as the 2019 Notes. This Registration Statement was effective on November 21, 2011.

At any time prior to February 1, 2014, the Company has the option to redeem up to 35% of the 2019 Notes at a redemption price of 107.25% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2019 Notes remains outstanding after such redemption. Prior to February 1, 2015, the Company has the option to redeem some or all of the 2019 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 1, 2015, the Company has the option to redeem some or all of the 2019 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning February 1, 2016 and 100% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date. The Company estimates that the fair value of this option is immaterial at December 31, 2011.

The 2019 Indenture restricts the Company s ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to certain exceptions and qualifications. If at any time when the 2019 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default (as defined in the 2019 Indenture) has occurred and is continuing, many of such covenants will terminate and the Company and its subsidiaries will cease to be subject to such covenants.

The 2019 Indenture contains customary events of default, including:

- default in any payment of interest on any 2019 Note when due, continued for 30 days;
- default in the payment of principal or premium, if any, on any 2019 Note when due;
- failure by the Company to comply with its other obligations under the 2019 Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries (as defined in the 2019 Indenture) in the aggregate principal amount of $10.0 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary (as defined in the 2019 Indenture) or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary;

failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary to pay certain final judgments aggregating in excess of $10.0 million within 60 days; and

any guarantee of the 2019 Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.