SM Energy Co
Form 10-K
February 21, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
þ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2012
or
o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Commission file number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	80203 (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, $.01 par value	New York Stock Exchange

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

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

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 o No þ

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. Yesþ Noo

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). Yesþ Noo

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.þ

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 þ	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the 64,586,179 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the registrant's common stock on June 29, 2012, the last business day of the registrant's most recently completed second fiscal quarter, of $49.11 per share, as reported on the New York Stock Exchange; was $3,171,827,251. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the registrant to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 14, 2013, the registrant had 66,205,901 shares of common stock outstanding, which is net of 50,581 treasury shares held by the registrant.

DOCUMENTS INCORPORATED BY REFERENCE
Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2013 annual meeting of stockholders to be filed within 120 days after December 31, 2012.

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PART I

When we use the terms “SM Energy,” “the Company,” “we,” “us,” or “our,” we are referring to SM Energy Company and its subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under Glossary of Oil and Gas Terms. Throughout this document we make statements that may be classified as “forward-looking.” Please refer to the Cautionary Information about Forward-Looking Statements section of this document for an explanation of these types of statements.

ITEMS 1. and 2. BUSINESS and PROPERTIES

General

We are an independent energy company engaged in the acquisition, exploration, development, and production of crude oil, natural gas, and natural gas liquids (also respectively referred to as “oil,” “gas,” and “NGLs” throughout the document) in onshore North America, with a current focus on oil and liquids-rich resource plays. We were founded in 1908 and incorporated in Delaware in 1915. Our initial public offering of common stock was in December 1992. Our common stock trades on the New York Stock Exchange under the ticker symbol “SM.”

Our principal offices are located at 1775 Sherman Street, Suite 1200, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

Our business strategy is to focus on the early capture of resource plays in order to create and then enhance value for our shareholders, while maintaining a strong balance sheet. We strive to leverage industry-leading acquisition, exploration, and operations teams to quickly acquire and test new resource play concepts at a reasonable cost. Once we have identified potential value through these efforts, our goal is to develop such potential through top-tier operational and project execution, and as appropriate, mitigate our risks by selectively divesting certain assets. We continually examine our portfolio for opportunities to improve the quality of our asset base in order to optimize our returns and preserve our financial strength.

Significant Developments in 2012

- Resource Play Delineation and Development Results in Record Production and Increase in Year-End Proved Reserve Estimates. Our estimated proved reserves increased 40 percent to 1,760.6 BCFE (293.4 MMBOE) at December 31, 2012, from 1,259.2 BCFE (209.9 MMBOE) at December 31, 2011. We added 900.2 BCFE through drilling activity during the year, which was primarily led by our efforts in the Eagle Ford shale in South Texas and the Bakken/Three Forks plays in North Dakota. We achieved record levels of production in 2012. Our average daily production was composed of 28.3 MBbl of oil, 328.0 MMcf of gas, and 16.7 MBbl of NGLs for an average equivalent production rate of 598.2 MMCFE per day, which was an increase of 29 percent from 465.0 MMCFE per day in 2011. Costs incurred in 2012 for drilling and exploration activities and acquisitions increased nine percent, to $1.7 billion, compared with $1.6 billion in 2011 due mainly to increased activity in plays with significant oil and NGL-rich gas components, such as our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Core Operational Areas below for additional discussion concerning our 2012 estimated proved reserves, production, and capital investment.

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- Impairments. We recorded impairment of proved properties expense of $208.9 million for the year ended December 31, 2012. During the fourth quarter of 2012, we recorded proved property impairment expense of $170.4 million. This non-cash charge was driven by downward engineering revisions that resulted in the write-down of Wolfberry assets in our Permian region. We also recorded proved property impairment expense of $38.5 million in the second quarter of 2012 related to our Haynesville shale assets in our Mid-Continent region due to low natural gas prices.
- Volatility and Decline in Commodity Prices. Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, natural gas, and NGLs, which can fluctuate dramatically. Oil prices were volatile throughout 2012, reaching their peak for the year in February when the spot price for NYMEX crude oil hit a high of $109.49 per Bbl. The spot price for NYMEX crude oil during 2012 was at its lowest of $77.69 per Bbl in June. The average spot price for oil during 2012 was $94.10 per Bbl, down slightly from the $95.05 per Bbl average NYMEX price in 2011. In 2012, oil prices were impacted by concerns over international supply disruptions, rising U.S. oil production, and changes in global economic growth expectations throughout the year.

Natural gas prices were also volatile in 2012. The spot price for natural gas at Henry Hub in Erath, Louisiana, a widely-used industry measuring point, averaged $2.75 per MMBtu in 2012, down from an average price of $4.00 per MMBtu in 2011. The 2012 average price was the lowest average annual price at Henry Hub since 1999. The high at Henry Hub for 2012 of $3.77 per MMBtu was recorded in November, and the low of $1.84 per MMBtu was reached in April. Natural gas prices were under downward pressure in 2012 as a result of sustained high natural gas inventories and rising natural gas production in the Marcellus and Eagle Ford basins. Natural gas prices rose throughout the remainder of the year after reaching their low in April.

NGL prices decreased throughout 2012 largely due to a growing supply of NGLs as increased numbers of industry participants targeted projects producing NGLs. The average spot price for NGLs in 2012 at Mont Belvieu was $44.91 per Bbl, which was down from $59.47 per Bbl in 2011. Please refer to Overview of the Company and Oil, Gas, and NGL Prices included in Part II, Item 7 of this report for additional information regarding our NGL prices.

Outlook for 2013

We enter 2013 with a projected $1.5 billion capital program, approximately $1.2 billion of which we expect to allocate to drilling and completion activities. Our 2013 capital program allocates all drilling and completion capital to oil and liquids-rich programs. Please refer to Core Operational Areas below and Outlook for 2013 under Part II, Item 7 of this report for additional discussion surrounding our capital plans for 2013.

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Core Operational Areas

Our operations are concentrated in four core operating areas in the onshore United States. Effective January 1, 2012, we combined our former ArkLaTex region with our Mid-Continent region, based in Tulsa, Oklahoma, for operational and reporting purposes. The following table summarizes estimated proved reserves, PV-10 reserve value, and production for the year ended December 31, 2012, for our core operating areas:

	South Texas & Gulf Coast		Rocky Mountain		Mid-Continent		Permian		Total [(1)]	
Proved Reserves										
Oil (MMBbl)	30.9		49.2		0.9		11.2		92.2	
Gas (Bcf)	530.7		42.7		233.4		26.6		833.4	
NGLs (MMBbl)	60.5		—		1.6		0.2		62.3	
BCFE [(1)]	1,079.2		337.9		248.6		94.8		1,760.6	
Relative percentage	61	%	19	%	14	%	6	%	100	%
Proved Developed %	43	%	65	%	89	%	93	%	57	%
PV-10 Values (in millions) [(2)]										
Proved Developed	$1,308.7		$974.4		$295.9		$403.6		$2,982.6	
Proved Undeveloped	591.5		248.5		4.8		21.7		866.5	
Total Proved	$1,900.2		$1,222.9		$300.7		$425.3		$3,849.1	
Relative percentage	49	%	32	%	8	%	11	%	100	%
Production										
Oil (MMBbl)	3.2		5.4		0.4		1.3		10.4	
Gas (Bcf)	59.1		4.4		53.4		3.2		120.0	
NGLs (MMBbl)	5.7		—		0.4		—		6.1	
BCFE [(1)]	112.7		36.9		58.1		11.3		218.9	
Avg. Daily Equivalents (MMCFE/d)	307.9		100.9		158.6		30.8		598.2	
Relative percentage	51	%	17	%	27	%	5	%	100	%

(1) Totals may not sum or recalculate due to rounding.

(2) The standardized measure PV-10 calculation is presented in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report. A reconciliation between the PV-10 reserve value and the after tax value is shown in the Reserves section below.

South Texas & Gulf Coast Region. Operations in our South Texas & Gulf Coast region are managed from our office in Houston, Texas. Our current operations in this region focus primarily on our Eagle Ford shale program. Our acreage position covers a significant portion of the western Eagle Ford shale play, including acreage in the oil, NGL-rich gas, and dry gas windows of the play. As of December 31, 2012, we had roughly 191,500 net acres in the play. We operate approximately 145,000 of the 191,500 net acres, with an average working interest of nearly 100 percent.

Nearly all of our capital deployed in the South Texas & Gulf Coast region in 2012 targeted our operated Eagle Ford shale program. Production in 2012 increased 62 percent from the 69.7 BCFE produced in 2011. Estimated proved reserves at year-end 2012 increased 123 percent from 483.6 BCFE at year-end 2011. Of the 2012 reserve additions in this region, approximately 767.3 BCFE of estimated proved reserves were added through drilling activities. The increase in production and proved reserves reflects the success we are having in our Eagle Ford shale program and the resulting consistent pace of investment. Our capital expenditures in our South Texas & Gulf Coast region decreased from $932.3 million in 2011 to $848.4 million in 2012, as a result of being carried for substantially all of our drilling and completion costs in our outside operated Eagle Ford program pursuant to our Acquisition and Development Agreement with Mitsui E&P Texas LP (“Mitsui”), an indirect subsidiary of Mitsui & Co., Ltd. (the “Acquisition and Development Agreement”).

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Rocky Mountain Region. Operations in our Rocky Mountain region are managed from our office in Billings, Montana. Our capital expenditures in 2012 primarily targeted the Bakken/Three Forks formations in the North Dakota portion of the Williston Basin, where we have approximately 80,500 net acres. In 2012, we continued to focus our drilling and completion activities in three main areas. In our Raven and Bear Den prospects, in Williams and McKenzie Counties, North Dakota, we have largely completed our drilling program intended to establish held by production status and have transitioned our program primarily to infill drilling. Our efforts are focused on optimizing our completions and spacing for development of the Bakken formation. In our Gooseneck prospect in Divide County, North Dakota, our efforts focused on the Three Forks formation, where we are also transitioning to infill drilling. As our program moves to infill development, we will continue our transition to multi-well pad drilling to improve the efficiency of our drilling and completion operations. Elsewhere in our Rocky Mountain region, we are in the exploratory phase of drilling test wells of various formations in the Powder River Basin. At year-end 2012, we had approximately 65,000 net acres in the Powder River Basin that we believe to be prospective in various target horizons.

Capital expenditures in our Rocky Mountain region increased from $288.0 million in 2011 to $406.8 million in 2012, as we increased activity in our Bakken/Three Forks program. Estimated proved reserves for the region at the end of 2012 increased 11 percent from 303.4 BCFE at year-end 2011. During the year, we added approximately 90.0 BCFE of proved reserves in this region through drilling activities. Total regional production for 2012 was up 38 percent from the 26.7 BCFE produced in 2011. The increase in capital, production, and proved reserves reflects the increased activity in our Bakken/Three Forks program.

Mid-Continent Region. Operations in our Mid-Continent region are managed from our office in Tulsa, Oklahoma. Our current operations in the Mid-Continent region are primarily focused on the horizontal development of the Granite Wash formation in western Oklahoma. Our Mid-Continent region also manages our Haynesville and Woodford shale assets, on which we minimized activity in 2012 due to the low natural gas price environment, which resulted in a decrease in our 2012 capital expenditures, production, and year-end reserves, as discussed below. Our 2012 Granite Wash program targeted the shallower, liquids-rich washes of our approximately 34,000 net acres in the play, substantially all of which are held by production.

In 2012, we incurred costs of $168.2 million in our Mid-Continent region for exploration, development, and acquisition activities, compared to $247.0 million incurred in 2011. In 2012, our Mid-Continent region’s production was 58.1 BCFE, a decrease from the 61.8 BCFE produced in 2011. Estimated proved reserves at the end of 2012 decreased 32 percent from 365.2 BCFE as of the end of 2011.

Permian Region. Operations in our Permian region are managed from our office in Midland, Texas. Our Permian region covers western Texas and eastern New Mexico. Our primary area of focus in this region is the delineation of our Mississippian limestone play, in which we hold approximately 65,500 net acres. In addition to this delineation program, we have an exploration program targeting various shale intervals in the Midland Basin. These programs resulted in an increase in our 2012 capital expenditures, as discussed below.

We incurred costs of $232.5 million in the region for exploration, development, and acquisition activities in 2012 compared to $80.7 million in 2011. A significant portion of the 2012 costs incurred in this region were for leasing activities and a drilling program that was weighted toward the last half of the year. The region’s 2012 production was 11.3 BCFE, compared to 2011 production of 11.5 BCFE. The decrease in production was due to natural decline in our Wolfberry assets as the field matured. Estimated proved reserves at the end of 2012 were 94.8 BCFE, which was a decrease from 2011 year-end proved reserves of 107.0 BCFE.

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Reserves

The table below presents summary information with respect to the estimates of our proved reserves for each of the years in the three-year period ended December 31, 2012. We engaged Ryder Scott Company, L.P. (“Ryder Scott”) to audit our internal engineering estimates of at least 80 percent of the PV-10 value of our estimated proved reserves in each year presented. The prices used in the calculation of proved reserve estimates as of December 31, 2012, were $94.71 per Bbl for oil, $2.76 per MMBtu for natural gas, and $45.65 per Bbl for NGLs.

Reserve estimates are inherently imprecise and estimates for new discoveries and undeveloped locations are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The PV-10 values shown in the following table are not intended to represent the current market value of our estimated proved reserves. Neither prices nor costs have been escalated. The actual quantities and present values of our estimated proved reserves may be less than we have estimated. No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the Securities and Exchange Commission (“SEC”), since the beginning of the last fiscal year. The following table should be read along with the section entitled Risk Factors – Risks Related to Our Business contained herein.

Our ability to replace our production is important to our sustainability. Please refer to the reserve replacement terms in the Glossary of Oil and Gas Terms section of this report for information describing how our reserve replacement metrics are calculated. Our reserve replacement percentages are calculated using information from the Oil and Gas Reserve Quantities section of Supplemental Oil and Gas Information located in Part II, Item 8 of this report.

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We believe the concept of reserve replacement as described in the Glossary of Oil and Gas Terms section of this report, as well as permutations that may include other captions of the Oil and Gas Reserve Quantities section of Supplemental Oil and Gas Information located in Part II, Item 8 of this report, are widely understood by those who make investment decisions related to the oil and gas exploration business.

	As of December 31,					
	2012		2011		2010	
Reserve data:						
Proved developed						
Oil (MMBbl)	58.8		50.3		46.0	
Gas (Bcf)	483.2		451.2		411.0	
NGLs (MMBbl)	27.2		15.2		—	
BCFE (1)	999.1		844.0		687.3	
Proved undeveloped						
Oil (MMBbl)	33.5		21.4		11.4	
Gas (Bcf)	350.2		212.8		229.0	
NGLs (MMBbl)	35.1		12.3		—	
BCFE (1)	761.5		415.2		297.2	
Total Proved						
Oil (MMBbl)	92.2		71.7		57.4	
Gas (Bcf)	833.4		664.0		640.0	
NGLs (MMBbl)	62.3		27.5		—	
BCFE (1)	1,760.6		1,259.2		984.5	
Proved developed reserves %	57	%	67	%	70	%
Proved undeveloped reserves %	43	%	33	%	30	%
Reserve value data (in millions):						
Proved developed PV-10	$2,982.6		$2,836.3		$2,053.5	
Proved undeveloped PV-10	866.5		624.9		290.8	
Total proved PV-10	$3,849.1		$3,461.2		$2,344.3	
Standardized measure of discounted future cash flows	$3,021.0		$2,580.0		$1,666.4	
Reserve replacement – drilling, excluding revisions	411	%	310	%	349	%
All in – including sales of reserves	329	%	262	%	293	%
All in – excluding sales of reserves	337	%	317	%	372	%
Reserve life (years)	8.0		7.4		8.9	

(1) Totals may not sum or recalculate due to rounding.

Note: NGL reserve data for 2010 has not been reclassified to conform to the current presentation given the immateriality of the volumes in 2010. Please refer to additional discussion under the caption Oil, Gas, and NGL Prices under Part II, Item 7 of this report.

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The following table reconciles the standardized measure of discounted future net cash flows (GAAP) to the PV-10 value (Non-GAAP). The difference is a result of the PV-10 value measure excluding the impact of income taxes. Please see the definitions of standardized measure of discounted future net cash flows and PV-10 value in the Glossary of Oil and Gas Terms.

	As of December 31, 2012	2011	2010
	(in millions)		
Standardized measure of discounted future net cash flows	$3,021.0	$2,580.0	$1,666.4
Add: 10 percent annual discount, net of income taxes	1,742.1	1,727.6	1,294.6
Add: future undiscounted income taxes	1,609.4	1,740.4	1,335.5
Undiscounted future net cash flows	$6,372.5	$6,048.0	$4,296.5
Less: 10 percent annual discount without tax effect	(2,523.4)	(2,586.8)	(1,952.2)
PV-10 value	$3,849.1	$3,461.2	$2,344.3

Proved Undeveloped Reserves

Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time period. As of December 31, 2012, we had no undrilled proved undeveloped reserves that had been on our books in excess of five years.

During 2012, the Company utilized reliable geologic and engineering technology to add approximately 177.7 BCFE of proved undeveloped reserves for locations that are more than one location removed from developed locations in the more developed portions of our Eagle Ford shale position. We incorporated public and proprietary data from multiple sources to establish geologic continuity of the formation and its producing properties. This included seismic data and interpretations (3-D and micro seismic), open hole log information (both vertically and horizontally collected), and petrophysical analysis of the log data, mud logs, gas sample analysis, measurements of total organic content, thermal maturity, test production, fluid properties, and core data as well as significant statistical performance data yielding predictable and repeatable reserve estimates within certain analogous areas. These locations were limited to only those areas where both established geologic consistency and sufficient statistical performance data could be demonstrated to provide reasonably certain results. In all other areas, we restricted proved undeveloped locations to immediate offsets to producing wells.

As of December 31, 2012, we had 761.5 BCFE of proved undeveloped reserves, which is an increase of 346.3 BCFE, or 83 percent, over proved undeveloped reserves of 415.2 BCFE at December 31, 2011. We added 549.7 BCFE of proved undeveloped reserves through our drilling program, 278.1 BCFE of which were extensions and discoveries, primarily in our Eagle Ford shale play, as well as an additional 271.6 BCFE of infill proved undeveloped reserves that were mostly concentrated in our assets in the Bakken/Three Forks and the Eagle Ford shale plays. A negative price revision of 29.1 BCFE was primarily due to gas weighted projects in our South Texas & Gulf Coast and Mid-Continent regions that no longer generated positive cash flow utilizing 12-month average benchmark pricing required by the SEC. Extensive delineation drilling in our Eagle Ford shale program during 2012 resulted in an increase in statistical data available in the play. This information, combined with extensive data demonstrating the geologic continuity of the reservoir, allowed us to add 491.2 BCFE of new proved undeveloped reserves in the Eagle Ford shale play and led to a downward engineering revision of 39.2 BCFE primarily r

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elated to previously booked Eagle Ford shale proved undeveloped locations. We removed 42.7 BCFE of proved undeveloped reserves from our books, primarily in the Woodford shale, due to low natural gas prices and as a result of the five-year limitation on the number of years that proved undeveloped reserves may be booked without being developed. During the year, we sold proved undeveloped assets in our Rocky Mountain region, comprising 3.2 BCFE. During 2012, we converted 89.2 BCFE of proved undeveloped reserves to proved developed reserves, primarily in our Eagle Ford shale and Bakken/Three Forks plays at a total capital cost of $203.6 million, of which $159.4 million was incurred in 2012. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement for discussion of the carry of 90 percent of certain of our drilling and completion costs. As of December 31, 2012, estimated future development costs relating to our proved undeveloped reserves are approximately $660 million, $451 million, and $359 million in 2013, 2014, and 2015, respectively.

Internal Controls Over Reserves Estimates

Our internal controls over the recording of proved reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with the SEC’s regulations. Our process for managing and monitoring the Company’s proved reserves is delegated to our reservoir engineering group, which is managed by Dennis A. Zubieta, our Vice President - Engineering, Evaluation and A&D, subject to the oversight of our management and the Audit Committee of our Board of Directors, as discussed below. Mr. Zubieta joined us in June 2000 as a Corporate Acquisition & Divestiture Engineer, assumed the role of Reservoir Engineer in February 2003, was appointed Reservoir Engineering Manager in August 2005, was appointed Vice President - Engineering and Evaluation in August 2008, and was appointed Vice President - Engineering, Evaluation and A&D in October 2012. Mr. Zubieta was employed by Burlington Resources Oil and Gas Company from June 1988 to May 2000 in various operations and reservoir engineering capacities. Mr. Zubieta received a Bachelor of Science degree in Petroleum Engineering from Montana Tech of The University of Montana in May 1988. Technical reviews are performed throughout the year by regional staff who evaluate geological and engineering data. This data, in conjunction with economic data and our ownership information, is used in making a determination of estimated proved reserve quantities. Our regional engineering technical staff do not report directly to Mr. Zubieta; they report to either their respective regional technical managers or directly to the regional manager. This is intended to promote objective and independent analysis within our regions in the reserves estimation process.

Third-party Reserves Audit

Ryder Scott performed an independent audit using its own engineering assumptions but with economic and ownership data we provided. Ryder Scott audits a minimum of 80 percent of our total calculated proved reserve PV-10 value. In the aggregate, the proved reserve values of our audited properties determined by Ryder Scott are required to be within 10 percent of our proved reserve valuations for the total company, as well as for each respective region. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services throughout the world for over seventy years. The technical person at Ryder Scott primarily responsible for overseeing our reserves audit is a Managing Senior Vice President who received a Bachelor of Science degree in Petroleum Engineering from the University of Missouri at Rolla in 1970, and who is a registered Professional Engineer in Colorado and Utah. He is also a member of the Society of Petroleum Engineers. The Ryder Scott 2012 report concerning our reserves is included as Exhibit 99.1.

In addition to a third party audit, our reserves are reviewed by management with the Audit Committee of our Board of Directors. Management, which includes our Chief Executive Officer, President and Chief Operating Officer, Executive Vice President and Chief Financial Officer, and Senior Vice President - Portfolio Development and Technical Services, is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The Audit Committee reviews a summary of the final reserves estimate in conjunction with Ryder Scott’s results and also meets with Ryder Scott representatives from time to time to discuss its processes and findings.

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Production

The following table summarizes the volumes and realized prices of oil, gas, and NGLs produced and sold from properties in which we held an interest during the periods indicated. Realized prices presented below exclude the effects of hedges and derivative contracts. Also presented is a summary of related production costs per MCFE.

	For the Years Ended December 31,		
	2012	2011	2010
Net production			
Oil (MMBbl)	10.4	8.1	6.4
Gas (Bcf)	120.0	100.3	71.9
NGLs (MMBbl)	6.1	3.5	—
BCFE	218.9	169.7	110.0
Eagle Ford net production(1)			
Oil (MMBbl)	3.1	2.5	0.8
Gas (Bcf)	58.1	32.9	13.0
NGLs (MMBbl)	5.7	3.1	—
BCFE	110.9	66.6	17.6
Average net daily production			
Oil (MBbl per day)	28.3	22.1	17.4
Gas (MMcf per day)	328.0	274.8	196.9
NGLs (MBbl per day)	16.7	9.6	—
MMCFE per day	598.2	465.0	301.4
Eagle Ford average net daily production(1)			
Oil (MBbl per day)	8.6	6.8	2.1
Gas (MMcf per day)	158.8	90.1	35.6
NGLs (MBbl per day)	15.5	8.6	—
MMCFE per day	303.1	182.5	48.3
Realized price			
Oil (per Bbl)	$85.45	$88.23	$72.65
Gas (per Mcf)	$2.98	$4.32	$5.21
NGLs (per Bbl)	$37.61	$53.32	$—
Per MCFE	$6.73	$7.85	$7.60
Production costs per MCFE			
Lease operating expense	$0.82	$0.88	$1.10
Transportation costs	$0.63	$0.51	$0.19
Production taxes	$0.33	$0.32	$0.48

(1) In each of the years 2012, 2011, and 2010, total estimated proved reserves attributed to our Eagle Ford shale properties exceeded 15 percent of our total proved reserves expressed on an equivalent basis.

Note: NGL production volumes and prices for 2010 have not been reclassified to conform to the current presentation given the immateriality of the volumes in 2010. Please refer to additional discussion under the caption Oil, Gas, and NGL Prices under Part II, Item 7 of this report.

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Productive Wells

As of December 31, 2012, we had working interests in 1,184 gross (730 net) productive oil wells and 3,018 gross (1,078 net) productive gas wells. Productive wells are either wells producing in commercial quantities or wells that are mechanically capable of commercial production, but are currently shut-in. Multiple completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of the current production mix.

Drilling Activity

All of our drilling activities are conducted using independent drilling contractors. We do not own any drilling equipment. The following table summarizes the number of operated and non-operated wells drilled or recompleted on our properties in 2012, 2011, and 2010, excluding non-consented projects, active injector wells, and any wells in which we own only a royalty interest:

	For the Years Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	127	47.2	125	32.1	191	36.5
Gas	337	124.5	273	81.0	72	17.0
Non-productive	10	6.3	11	4.0	4	1.1
	474	178.0	409	117.1	267	54.6
Exploratory wells:						
Oil	9	6.9	16	6.3	36	11.5
Gas	8	6.8	48	8.6	83	37.9
Non-productive	8	6.8	3	1.0	1	0.8
	25	20.5	67	15.9	120	50.2
Total	499	198.5	476	133.0	387	104.8

A productive well is an exploratory, development, or extension well that is producing oil, gas, and/or NGLs or that is capable of commercial production of those products. A non-productive well, frequently referred to within the industry as a dry hole, is an exploratory, development, or extension well that proves to be incapable of producing either oil, gas, and/or NGLs in commercial quantities.

As defined by the SEC, an exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. A development well is a well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive and is part of a development project, which is defined as the means by which petroleum resources are brought to economically producible status. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of equipment for production of oil, gas, and/or NGLs, or in the case of a dry well, the reporting to the appropriate authority that the well has been plugged and abandoned.

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In addition to the wells drilled and completed in 2012 (included in the table above), as of February 14, 2013, we were participating in the drilling of 44 gross wells. We operate 25 of these wells on a gross basis (17 on a net basis) and other companies operate the remaining 19 gross wells (two on a net basis). With respect to completion activity, at such date, there were 234 gross wells in which we have an interest that were being completed. We operate 45 of these completion activities on a gross basis (40 on a net basis), and were participating in 189 gross (34 net) non-operated completion activities. Substantially all of these operations relate to the drilling of wells during the primary term of the respective oil and gas lease or leases.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leasehold, fee properties, and mineral servitudes held by us as of December 31, 2012. Undeveloped acreage includes leasehold interests that contain proved undeveloped reserves.

	Developed Acres (1)		Undeveloped Acres (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	71,750	24,794	39,104	30,989	110,854	55,783
Montana	57,586	39,877	312,758	210,226	370,344	250,103
Nevada	—	—	197,634	197,634	197,634	197,634
North Dakota	158,489	102,579	105,932	62,115	264,421	164,694
Oklahoma	249,706	82,441	64,642	28,433	314,348	110,874
Pennsylvania	282	282	26,270	22,803	26,552	23,085
Texas	245,699	152,195	570,504	320,510	816,203	472,705
Wyoming	45,261	21,897	267,961	189,825	313,222	211,722
Other (3)	4,430	2,011	42,926	29,937	47,356	31,948
	833,203	426,076	1,627,731	1,092,472	2,460,934	1,518,548
Louisiana Fee Properties	10,499	10,499	14,415	14,415	24,914	24,914
Louisiana Mineral Servitudes	7,426	4,217	4,769	4,407	12,195	8,624
	17,925	14,716	19,184	18,822	37,109	33,538
Total (4)	851,128	440,792	1,646,915	1,111,294	2,498,043	1,552,086

(1) Developed acreage is acreage assigned to producing wells for the state approved spacing unit for the producing formation. Our developed acreage that includes multiple formations with different well spacing requirements may be considered undeveloped for certain formations, but has been included only as developed acreage in the presentation above.

(2) Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and/or NGLs regardless of whether such acreage contains estimated net proved reserves.

(3) Includes interests in Arkansas, Colorado, Kansas, Illinois, Mississippi, Nebraska, New Mexico, and Utah.

(4) As of the filing date of this report, we had approximately 63,368, 79,048, and 162,422 net acres scheduled to expire by December 31, 2013, 2014, and 2015, respectively, if production is not established or we take no other action to extend the terms of the applicable lease or leases.

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Delivery Commitments

As of December 31, 2012, we had gathering, processing, and transportation through-put commitments with various parties that require us to deliver fixed, determinable quantities of production over specified time frames. We have an aggregate minimum commitment to deliver 1,515 Bcf of natural gas and 36 MMBbls of oil. These contracts expire at various dates through 2023. We are required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment for natural gas is projected, we have rights under certain contracts to arrange for third party gas to be delivered, and such volume will count toward our minimum volume commitment. Our current production is insufficient to offset these aggregate contractual liabilities, but we expect to fulfill the delivery commitments with production from the future development of our proved undeveloped reserves and from the future development of resources not yet characterized as proved reserves in our Eagle Ford shale and Haynesville shale resource plays. Therefore, we currently do not expect any significant shortfalls.

Major Customers

For the year ended December 31, 2012, we had two major customers, Regency Gas Services LLC and Plains Marketing LP, which accounted for approximately 21 percent and 13 percent, respectively, of our total revenue. During 2011 and 2010, we had one major customer, Regency Gas Services LLC, which individually accounted for approximately 18 percent and 11 percent, respectively, of our total revenue.

Employees and Office Space

As of February 14, 2013, we had 725 full-time employees. None of our employees are subject to a collective bargaining agreement, and we consider our relations with our employees to be good.

As of December 31, 2012, we leased approximately 98,000 square feet of office space in Denver, Colorado for our executive and administrative offices; approximately 45,000 square feet of office space in Tulsa, Oklahoma; approximately 62,000 square feet in Houston, Texas; approximately 30,000 square feet in Billings, Montana; approximately 22,000 square feet in Midland, Texas; approximately 7,000 total square feet in Williston and Watford City, North Dakota; and approximately 2,000 square feet in Casper, Wyoming. As of December 31, 2012, we own field office facilities containing approximately 12,000 square feet of office space in Catarina, Texas; approximately 3,000 square feet of office space in Belfield, North Dakota; and approximately 4,000 square feet of office space in Sidney, Montana.

Title to Properties

Substantially all of our interests are held pursuant to oil and gas leases from third parties. A title opinion is usually obtained prior to the commencement of initial drilling operations. We have obtained title opinions or have conducted other title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. Substantially all of our producing properties are subject to mortgages securing indebtedness under our credit facility, royalty and overriding royalty interests, liens for current taxes, and other burdens that we believe do not materially interfere with the use of, or affect the value of, such properties. We typically perform only minimal title investigation before acquiring undeveloped leasehold acreage.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during winter months and decrease during summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can place increased demand on storage volumes. Demand for oil and heating oil is also generally higher in the winter and the summer driving season, although oil prices are impacted more significantly by global supply and demand. Seasonal

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anomalies, such as mild winters, sometimes lessen these fluctuations. The impact of seasonality on oil has been somewhat magnified by overall supply and demand economics attributable to the narrow margin of worldwide production capacity in excess of existing worldwide demand for oil. Certain of our drilling, completion, and other operations are also subject to seasonal limitations. Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate. See Risk Factors - Risks Related to Our Business for additional discussion.

Competition

The oil and gas industry is intensely competitive, particularly with respect to acquiring prospective oil and natural gas properties. We believe our leasehold position provides a sound foundation for a solid drilling program and our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, as well as our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete in our core operating areas. However, we face intense competition from a substantial number of major and independent oil and gas companies, which in some cases have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have refining operations, market refined products, own drilling rigs and other equipment, and generate electricity.

We also compete with other oil and gas companies in attempting to secure drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells. Consequently, we may face shortages or delays in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may be affected by future new energy, climate-related, financial, and/or other policies, legislation, and regulations.

In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other professionals. Throughout the oil and gas industry, the need to attract and retain talented people has grown at a time when the availability of individuals with these skills is becoming more limited due to the evolving demographics of our industry. We are not insulated from the competition for quality people, and we must compete effectively in order to be successful.

Government Regulations

Our business is extensively regulated by numerous federal, state, and local laws and governmental regulations. These laws and regulations may be changed from time to time in response to economic or political conditions, or other developments, and our regulatory burden may increase in the future. Laws and regulations have the potential of increasing our cost of doing business and, consequently, could affect our profitability. However, we do not believe that we are affected to a materially greater or lesser extent than others in our industry.

Energy Regulations. Many of the states in which we conduct our operations have adopted laws and regulations governing the exploration for and production of oil, gas, and NGLs, including laws and regulations that require permits for the drilling of wells, impose bonding requirements in order to drill or operate wells, and govern the timing of drilling and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to various state conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of oil and gas properties. In addition, state conservation laws sometimes establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas, and may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

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Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed regulations and orders that are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and must comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM may suspend or terminate our operations on federal leases. In May 2010, the BLM adopted changes to its oil and gas leasing program that require, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, increased public engagement in the development of master leasing and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process. These changes have increased the amount of time and regulatory costs necessary to obtain oil and gas leases administered by the BLM.

Our sales of natural gas are affected by the availability, terms, and cost of gas pipeline transportation. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce. FERC's current regulatory framework generally provides for a competitive and open access market for sales and transportation of natural gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect the sales prices we receive for natural gas production. In addition, the less stringent regulatory approach currently pursued by FERC and the United States Congress may not continue indefinitely.

Environmental, Health and Safety Matters

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

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

These laws, rules 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 natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly permitting, waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

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The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States and states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, U.S. Army Corps of Engineers or analogous state agencies. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990 ("OPA") addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in governmental penalties and civil liability.

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Air emissions. The federal Clean Air Act ("CAA"), and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. Legislative and regulatory initiatives related to climate change could have an adverse effect on our operations and the demand for oil and gas. See "Risk Factors - Risks Related to Our Business - Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil, natural gas and NGLs." In addition to the effects of regulation, the meteorological effects of global climate change could pose additional risks to our operations, including physical damage risks associated with more frequent, more intensive storms and flooding, and could adversely affect the demand for our products.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our well drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete well drilling and development and could adversely affect our future production from those areas.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having 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. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay development of some of our oil and natural gas projects.

OSHA and other laws and regulation. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe that we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

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Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's (the "SDWA") Underground Injection Control Program. The federal SDWA protects the quality of the nation's public drinking water through the adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas activities using hydraulic fracturing techniques, which could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and delays, all of which could adversely affect our financial position, results of operations and cash flows. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot give any assurance that we will not be adversely affected in the future.

Cautionary Information about Forward-Looking Statements

This Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project," "will," and similar ex intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-K, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- future oil, gas, and NGL production estimates;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;

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- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section in Item 7 of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the Risk Factors section of this report, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- the continued weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital that is required to replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on non-operated properties;
- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we have an interest may be defective;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with divestitures, joint ventures, farm-downs, farm-outs and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;

- our commodity derivative contracts may result in financial losses or may limit the prices that we receive for oil, gas, and NGL sales;
- the inability of one or more of our vendors, customers, or contractual counterparties to meet their obligations;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that lower oil, gas, or NGL prices could have on the amount we are able to borrow under our credit facility;
- the possibility that our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; and
- litigation, environmental matters, the potential impact of government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and that actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing date of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

Available Information

Our internet website address is www.sm-energy.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. We also make available through our website's corporate governance section our Corporate Governance Guidelines, Code of Business Conduct and Ethics, Financial Code of Ethics, and the Charters of the Audit, Compensation, Executive, and Nominating and Corporate Governance Committees of our Board of Directors. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

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Glossary of Oil and Gas Terms

The oil and gas terms defined in this section are used throughout this report. The definitions of the terms developed reserves, exploratory well, field, proved reserves, and undeveloped reserves have been abbreviated from the respective definitions under SEC Rule 4-10(a) of Regulation S-X, as amended effective for fiscal years ending on or after December 31, 2009. The entire definitions of those terms under Rule 4-10(a) of Regulation S-X can be located through the SEC's website at www.sec.gov.

Bbl. One stock tank barrel, or 42 U.S. gallons of liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet, used in reference to natural gas.

BCFE. Billion cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

BTU. One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

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

Developed reserves. Reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

Dry hole. A well found to be incapable of producing either oil, natural gas, and/or NGLs in commercial quantities.

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

Fee properties. The most extensive interest that can be owned in land, including surface and mineral (including oil and natural gas) rights.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and development cost. Expressed in dollars per MCFE. Finding and development cost metrics provide information as to the cost of adding proved reserves from various activities, and are widely utilized within the exploration and production industry, as well as by investors. The information used to calculate these metrics is included in the Supplemental Oil and Gas Information section in Part II, Item 8 of this report. It should be noted that finding and development cost metrics have limitations. For example, exploration efforts related to a particular set of proved reserve additions may extend over several years. As a result, the exploration costs incurred in earlier periods are not included in the amount of exploration costs incurred during the period in which that set of proved reserves is added. In addition, consistent with industry practice, future capital costs to develop proved undeveloped reserves are not included in costs incurred. Since the additional development costs that will need to be incurred in

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the future before the proved undeveloped reserves are ultimately produced are not included in the amount of costs incurred during the period in which those reserves were added, those development costs in future periods will be reflected in the costs associated with adding a different set of reserves. The calculations of various finding and development cost metrics are explained below.

Finding and development cost – Drilling, excluding revisions. Calculated by dividing the amount of costs incurred for development and exploration activities, by the amount of estimated net proved reserves added through discoveries, extensions, and infill drilling, during the same period.

Finding and development cost – Drilling, including revisions. Calculated by dividing the amount of costs incurred for development and exploration activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, and revisions of previous estimates, during the same period.

Finding and development cost – Drilling and acquisitions, excluding revisions. Calculated by dividing the amount of costs incurred for development, exploration, and acquisition of proved properties, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, and acquisitions, during the same period.

Finding and development cost – Drilling and acquisitions, including revisions. Calculated by dividing the amount of costs incurred for development, exploration, and acquisition of proved properties, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, revisions of previous estimates, and acquisitions, during the same period.

Finding and development cost –All in, including sales of reserves. Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates less sales of reserves, during the same period.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Gross acre. An acre in which a working interest is owned.

Gross well. A well in which a working interest is owned.

Horizontal wells. Wells that are drilled at angles greater than 70 degrees from vertical.

Lease operating expenses. The expenses incurred in the lifting of crude oil, natural gas, and/or associated liquids from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition, drilling, or completion costs.

MBbl. One thousand barrels of crude oil or other liquid hydrocarbons.

MMBbl. One million barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet, used in reference to natural gas.

MCFE. One thousand cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

MMcf. One million cubic feet, used in reference to natural gas.

MMCFE. One million cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

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MMBtu. One million British thermal units.
Net acres or net wells. Sum of our fractional working interests owned in gross acres or gross wells.
Net asset value per share. The result of the fair market value of total assets less total liabilities, divided by the total number of outstanding shares of common stock.
NGLs. The combination of ethane, propane, butanes, and natural gasolines that when removed from natural gas become liquid under various levels of higher pressures and lower temperatures.
NYMEX WTI. New York Mercantile Exchange West Texas Intermediate.
OPIS. Oil Price Information Service Mont Belvieu.
PV-10 value (Non-GAAP). The present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period. This is a Non-GAAP measure.
Productive well. A well that is producing crude oil, natural gas, and/or NGLs or that is capable of commercial production of those products.
Proved reserves. Those quantities of oil, gas, and NGLs 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
Recompletion. The completion in an existing wellbore in a formation other than that in which the well has previously been completed.
Reserve life. Expressed in years, represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

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Reserve replacement. Reserve replacement metrics are used as indicators of a company's ability to replenish annual production volumes and grow its reserves, and provide information related to how successful a company is at growing its proved reserve base. These are believed to be useful non-GAAP measures that are widely utilized within the exploration and production industry, as well as by investors. They are easily calculable metrics, and the information used to calculate these metrics is included in the Supplemental Oil and Gas Information section of Part II, Item 8 of this report. It should be noted that reserve replacement metrics have limitations. They are limited because they typically vary widely based on the extent and timing of new discoveries and property acquisitions. Their predictive and comparative value is also limited for the same reasons. In addition, because the metrics do not embed the cost or timing of future production of new reserves, they cannot be used as a measure of value creation. The calculations of various reserve replacement metrics are explained below.

Reserve replacement – Drilling, excluding revisions. Calculated as a numerator comprised of the sum of reserve extensions and discoveries and infill reserves in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity.

Reserve replacement – Drilling, including revisions. Calculated as a numerator comprised of the sum of reserve extensions, discoveries, and infill reserves, and revisions of previous estimates in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity with an adjustment for revisions.

Reserve replacement – Drilling and acquisitions, excluding revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions, discoveries, and infill reserves in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities.

Reserve replacement – Drilling and acquisitions, including revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions, discoveries, and infill reserves, and revisions of previous estimates in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities with an adjustment for revisions.

Reserve replacement percentage – All in, excluding sales of reserves. The sum of reserve extensions and discoveries, infill drilling, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.

Reserve replacement percentage –All in, including sales of reserves. The sum of sales of reserves, infill drilling, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.

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

Resource play. A term used to describe an accumulation of crude oil, natural gas, and/or associated liquid resources known to exist over a large areal expanse, which when compared to a conventional play typically has a lower expected geological and/or commercial development risk.

Royalty. The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil, natural gas, and NGLs produced and sold unencumbered by expenses relating to the drilling, completing, and operating of the affected well.

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Royalty interest. An interest in an oil and natural gas property entitling the owner to shares of crude oil, natural gas, and NGL production free of costs of exploration, development, and production operations.
Seismic. The sending of energy waves or sound waves into the earth and analyzing the wave reflections to infer the type, size, shape, and depth of subsurface rock formations.
Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.
Standardized measure of discounted future net cash flows. The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, and a 10 percent annual discount rate. The information for this calculation is included in the supplemental information regarding disclosures about oil and gas producing activities following the Notes to Consolidated Financial Statements included in this report.
Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and/or NGLs regardless of whether such acreage contains estimated net proved reserves.
Undeveloped reserves. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.
Working interest. The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production, sales, and costs.

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ITEM 1A. RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in us.

Risks Related to Our Business

Crude oil, natural gas, and NGL prices are volatile, and declines in prices adversely affect our profitability, financial condition, cash flows, access to capital, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and natural gas properties depend heavily on the prices we receive for crude oil, natural gas and NGL sales. Crude oil, natural gas, and NGL prices also affect our cash flows available for capital expenditures and other items, our borrowing capacity, and the amount and value of our crude oil, natural gas, and NGL reserves. For example, the amount of our borrowing base under our credit facility is subject to periodic redeterminations based on crude oil, natural gas, and NGL prices specified by our bank group at the time of redetermination. In addition, we may have crude oil and natural gas property impairments or downward revisions of estimates of proved reserves if prices fall significantly.

Historically, the markets for crude oil, natural gas, and NGLs have been volatile, and they are likely to continue to be volatile. Wide fluctuations in crude oil, natural gas, and NGL prices may result from relatively minor changes in the supply of and demand for crude oil, natural gas, and NGLs, market uncertainty, and other factors that are beyond our control, including:

- global and domestic supplies of crude oil, natural gas, and NGLs, and the productive capacity of the industry as a whole;
- the level of consumer demand for crude oil, natural gas, and NGLs;
- overall global and domestic economic conditions;
- weather conditions;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities in regional or localized areas that may affect the realized price for crude oil, natural gas, or NGLs;
- liquefied natural gas deliveries to and from the United States;
- the price and level of foreign imports of crude oil, refined petroleum products, and liquefied natural gas;
- the price and availability of alternative fuels;
- technological advances and regulations affecting energy consumption and conservation;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting countries to agree to and maintain crude oil price and production controls;
- political instability or armed conflict in crude oil or natural gas producing regions;
- strengthening and weakening of the United States dollar relative to other currencies; and
- governmental regulations and taxes.

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These factors and the volatility of crude oil, natural gas, and NGL markets make it extremely difficult to predict future crude oil, natural gas, and NGL price movements with any certainty. Declines in crude oil, natural gas, and NGL prices would reduce our revenues and could also reduce the amount of crude oil, natural gas, and NGLs that we can produce economically, which could have a materially adverse effect on us.

Continued weakness in economic conditions or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

United States and global economies and financial systems have recently experienced turmoil and upheaval characterized by extreme volatility and declines in prices of securities, diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse, or sale of financial institutions, increased levels of unemployment, and an unprecedented level of intervention by the United States federal government and other governments. Although some portions of the economy appear to have stabilized and there have been signs of the beginning of a recovery, the extent and timing of a recovery, and whether it can be sustained, are uncertain. Continued weakness in the United States or other large economies could materially adversely affect our business and financial condition. For example:

- the demand for crude oil, natural gas, and NGLs in the United States has declined and may remain at low levels or further decline if economic conditions remain weak, and continue to negatively impact our revenues, margins, profitability, operating cash flows, liquidity, and financial condition;
- natural gas prices have recently been lower than at various times in the last decade because of increased supply resulting from, among other things, increased drilling in unconventional reservoirs, and reduced demand in connection with the recent recession, which sustained low prices could affect our financial condition and results of operations;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables;
- the liquidity available under our credit facility could be reduced if any lender is unable to fund its commitment;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business, including for exploration and/or development of our reserves;
- our commodity derivative contracts could become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection; and
- variable interest rate spread levels, including for LIBOR and the prime rate, could increase significantly, resulting in higher interest costs for unhedged variable interest rate based borrowings under our credit facility.

If we are unable to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find, develop, or acquire crude oil, natural gas, and NGL reserves that are economically producible. Our properties produce crude oil, natural gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate and develop or acquire new crude oil, natural gas, and NGL reserves to replace those being depleted by production. In addition, competition for crude oil and natural gas properties is intense, and many of our competitors have financial, technical, human, and other resources needed to evaluate and integrate acquisitions that are substantially greater than those available to us.

In the event we do complete an acquisition, its successful impact on our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future crude oil, natural

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gas, and NGL prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties, and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Without successful drilling or acquisition activities, our reserves and production will decline over time. Substantial capital is required to replace our reserves.

We must make substantial capital expenditures to find, acquire, develop, and produce crude oil, natural gas, and NGL reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, prices received for crude oil, natural gas, and NGL sales, our success in locating and developing and acquiring new reserves, and the orderly functioning of credit and capital markets. If crude oil, natural gas, and NGL prices decrease or if we encounter operating difficulties that result in our cash flows from operations being less than expected, we must reduce our capital expenditures unless we can raise additional funds through debt or equity financing or the divestment of assets. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms, and the proceeds offered to us for potential divestitures may not always be of acceptable value to us.

If our revenues decrease due to lower crude oil, natural gas, or NGL prices, decreased production, or other reasons, and if we cannot obtain funding through our credit facility, other acceptable debt or equity financing arrangements, or through the sale of assets, our ability to execute development plans, replace our reserves, maintain our acreage, or maintain production levels could be greatly limited.

Competition in our industry is intense, and many of our competitors have greater financial, technical, and human resources than we do.

We face intense competition from major oil and gas companies, independent oil and gas exploration and production companies, financial buyers, and institutional and individual investors who seek oil and gas investments throughout the world, as well as the equipment, expertise, labor, and materials required to operate crude oil and natural gas properties. Many of our competitors have financial, technical, and other resources vastly exceeding those available to us, and many crude oil and natural gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for the properties. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We may not be successful in acquiring and developing profitable properties in the face of this competition.

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We also compete for human resources. Over the last few years, the need for talented people across all disciplines in the industry has grown, while the number of talented people available has not grown at the same pace, and in many cases, is declining due to the demographics of the industry.

The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

The actual quantities and present value of our proved crude oil, natural gas, and NGL reserves may be less than we have estimated.

This report and other of our SEC filings contain estimates of our proved crude oil, natural gas, and NGL reserves and the estimated future net revenues from those reserves. These estimates are based on various assumptions, including assumptions required by the SEC relating to crude oil, natural gas, and NGL prices, drilling and completion costs, gathering and transportation costs, operating expenses, capital expenditures, effects of governmental regulation, taxes, timing of operations, and availability of funds. The process of estimating crude oil, natural gas, and NGL reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. These estimates are dependent on many variables, and therefore changes often occur as our knowledge of these variables evolve. Therefore, these estimates are inherently imprecise. In addition, the reserve estimates we make for properties that do not have a significant production history may be less reliable than estimates for properties with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates, and the timing of development expenditures.

Actual future production, prices for crude oil, natural gas, and NGLs, revenues, production taxes, development expenditures, operating expenses, and quantities of producible crude oil, natural gas, and NGL reserves will most likely vary from those estimated. Any significant variance of any nature could materially affect the estimated quantities of and present value related to proved reserves disclosed by us, and the actual quantities and present value may be significantly less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration, operations and development activity, prevailing crude oil, natural gas, and NGL prices, costs to develop and operate properties, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties.

As of December 31, 2012, 43 percent, or 761.5 BCFE, of our estimated proved reserves were proved undeveloped, and two percent, or 40.8 BCFE, were proved developed non-producing. In order to develop our proved undeveloped reserves, as of December 31, 2012, we estimate approximately $1.6 billion of capital expenditures would be required. Production revenues from proved developed non-producing reserves will not be realized until sometime in the future and after some investment of capital. In order to develop our proved developed non-producing reserves, as of December 31, 2012, we estimate capital expenditures of approximately $30 million would be required. Although we have estimated our proved reserves and the costs associated with these proved reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled, and actual results may not occur as estimated.

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You should not assume that the PV-10 value and standardized measure of discounted future net cash flows included in this report represent the current market value of our estimated proved crude oil, natural gas, and NGL reserves. Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. For example, values of our reserves as of December 31, 2012, were estimated using a calculated 12-month average sales price of $2.76 per MMBtu of natural gas (NYMEX Henry Hub spot price), $94.71 per Bbl of oil (NYMEX WTI spot price), and $45.65 per Bbl of NGL (OPIS spot price). We then adjust these base prices to reflect appropriate basis, quality, and location differentials over that period in estimating our proved reserves. During 2012, our monthly average realized natural gas prices, excluding the effect of derivative cash settlements, were as high as $3.79 per Mcf and as low as $2.18 per Mcf. For the same period, our monthly average realized crude oil prices before the effect of derivative cash settlements were as high as $92.23 per Bbl and as low as $71.33 per Bbl, and were as high as $47.08 per Bbl and as low as $27.84 per Bbl for NGLs. Many other factors will affect actual future net cash flows, including:

- amount and timing of actual production;
- supply and demand for crude oil, natural gas, and NGLs;
- curtailments or increases in consumption by oil purchasers and natural gas pipelines; and
- changes in government regulations or taxes, including severance and excise taxes.

The timing of production from oil and natural gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing the PV-10 value. In addition, the 10 percent discount factor required by the SEC to be used to calculate the PV-10 value for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates, costs of capital, and other risks to which our business and the oil and natural gas industry in general are subject.

Our property acquisitions may not be worth what we paid due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors sometimes beyond our control. These factors include exploration potential, future crude oil, natural gas, and NGL prices, operating costs, and potential environmental and other liabilities. These assessments are not precise and their accuracy is inherently uncertain.

In connection with our acquisitions, we typically perform a customary review of the acquired properties that will not necessarily reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties.

In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such acquisitions may be limited.

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Integrating acquired properties and businesses involves a number of other special risks, including the risk that management may be distracted from normal business concerns by the need to integrate operations and systems as well as retain and assimilate additional employees. Therefore, we may not be able to realize all of the anticipated benefits of our acquisitions.

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

Some of our properties, including a portion of our operations in the Eagle Ford shale in South Texas, are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including the nature and timing of drilling and operational activities, the operator’s skill and expertise, compliance with environmental, safety and other regulations, the approval of other participants in such properties, the selection and application of suitable technology, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and materially and adversely affect our financial condition and results of operations.

We rely on third-party service providers to conduct the drilling and completion operations on properties we operate.

Where we are the operator of a property, we rely on third-party service providers to perform necessary drilling and completion operations. The ability of third-party service providers to perform such drilling and completion operations will depend on those service providers’ ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, natural gas liquids and natural gas, prevailing economic conditions and financial, business and other factors. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the property and adversely affect our financial condition and results of operations.

Title to the properties in which we have an interest may be impaired by title defects.

We generally rely on title reports in acquiring oil and gas leasehold interests and obtain title opinions only on significant properties that we drill. 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. Title insurance is not available for oil and gas properties. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and title abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. Generally, under the terms of the operating agreements affecting our properties, any monetary loss attributable to a loss of title is to be borne by all parties to any such agreement in proportion to their interests in such property. A material title defect can reduce the value or render a property worthless, thus adversely affecting our financial condition, results of operations and operating cash flow if such property is of sufficient value.

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Exploration and development drilling may not result in commercially producible reserves.

Crude oil and natural gas drilling and production activities are subject to numerous risks, including the risk that no commercially producible crude oil, natural gas, or associated liquids will be found. The cost of drilling and completing wells is often uncertain, and crude oil, natural gas or associated liquids drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- title problems;
- disputes with owners or holders of surface interests on or near areas where we operate;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- hurricanes or other adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, water, sand, and other supplies.

The prevailing prices for crude oil, natural gas, and NGLs affect the cost of and the demand for drilling rigs, completion and production equipment, and other related services. However, changes in costs may not occur simultaneously with corresponding changes in commodity prices. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region. In addition, the recent economic and financial downturn has adversely affected the financial condition of some drilling contractors, which may constrain the availability of drilling services in some areas.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a materially adverse effect on our ability to explore on or develop our properties.

The wells we drill may not be productive, and we may not recover all or any portion of our investment in such wells.

The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if crude oil, natural gas, or NGLs are present, or whether they can be produced economically. The cost of drilling, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover drilling and completion costs. Even if sufficient amounts of crude oil, natural gas, or NGLs exist, we may damage a potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing a well, resulting in a reduction in or no production from the well, significant expense to repair the well, or the loss and abandonment of the well.

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Drilling results in our newer shale plays may be more uncertain than results in shale plays that are more developed and have longer established production histories. For example, our experience with horizontal drilling in the Eagle Ford shale play, as well as the industry's drilling and production history, is more limited than in many shale plays, such as the Barnett or Woodford shales, and we and the industry generally have less information with respect to the ultimate recoverability of reserves and the production decline rates in these shales than other areas with longer histories of drilling and production. Completion techniques that have proven to be successful in other shale formations to maximize recoveries are being used in the early development of these new shales; however, we can provide no assurance of the ultimate success of these drilling and completion techniques.

In addition, a significant part of our strategy involves increasing our inventory of drilling locations. Such multi-year drilling inventories can be more susceptible to long-term uncertainties that could materially alter the occurrence or timing of actual drilling. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled, although we have the present intent to do so, or if we will be able to produce crude oil, natural gas, or NGLs from these or any other potential drilling locations.

Our future drilling activities may not be successful. Our overall drilling success rate or our drilling success rate within a particular area may decline. In addition, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Unless production is established within the spacing units covering undeveloped acres on which our drilling locations are identified, the leases for such acreage will expire and we would lose our right to develop the related properties. Our total net acreage expiring in the next three years represents approximately 27 percent of our total net undeveloped acreage at December 31, 2012. Although we have identified numerous potential drilling locations, we may not be able to economically produce crude oil, natural gas, or NGLs from all of them and our actual drilling activities may materially differ from those presently identified, which could adversely affect our financial condition, results of operations and operating cash flow.

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 and delineation 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.

Many of our operations 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 recover 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 and other equipment the entire length of the well bore during completion operations, being able to recover such tools and other equipment, and successfully cleaning out the well bore after completion of the final fracture stimulation.

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, limited access to gathering systems and takeaway capacity, and/or prices for crude oil, natural gas, and NGL decline, then the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of oil and gas properties and the value of our undeveloped acreage could decline in the future.

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Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.

We inject water into formations on some of our properties to increase the production of crude oil, natural gas, and associated liquids. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of crude oil, natural gas, and associated liquids in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. In addition, if proposed legislation and regulatory initiatives relating to hydraulic fracturing become law, the cost of some of these enhanced recovery methods could increase substantially.

Our commodity derivative contract activities may result in financial losses or may limit the prices that we receive for crude oil, natural gas, and NGL sales.

To mitigate a portion of the exposure to potentially adverse market changes in crude oil, natural gas, and NGL prices and the associated impact on cash flows, the Company has entered into various derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for crude oil, natural gas, and NGLs. As of December 31, 2012, we were in a net accrued asset position of $38.7 million with respect to our crude oil, natural gas, and NGL derivative activities. These activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- one or more counterparties to our commodity derivative contracts default on their contractual obligations; or
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative contract arrangement.

The risk of one or more counterparties defaulting on their obligations is heightened by the recent global and domestic economic and financial downturn affecting many banks and other financial institutions, including our counterparties and their affiliates. These circumstances may adversely affect the ability of our counterparties to meet their obligations to us pursuant to derivative transactions, which could reduce our revenues and cash flows from realized derivative cash settlements. As a result, our financial condition, results of operations, and cash flows could be materially affected in an adverse way if our counterparties default on their contractual obligations under our commodity derivative contracts.

In addition, commodity derivative contracts may limit the prices that we receive for our crude oil, natural gas and NGL sales if crude oil, natural gas, or NGL prices rise substantially over the price established by the commodity derivative contract.

The inability of customers or co-owners of assets to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from crude oil, natural gas, and NGL sales or joint interest billings to co-owners of oil and gas properties we operate. This concentration of customers and joint interest owners may impact our overall credit risk because these entities may be similarly affected by various economic and other conditions, including the recent global and domestic economic and financial downturn.

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In addition, for the year ended December 31, 2012, we had two major customers, Regency Gas Services LLC and Plains Marketing LP, which accounted for approximately 21 percent and 13 percent, respectively, of our total production revenue. During 2011 and 2010, we had one major customer, Regency Gas Services LLC, individually account for approximately 18 percent and 11 percent, respectively, of our total production revenue. The loss of one or more of these customers could reduce competition for our products and negatively impact the prices at which we sell such products.

We have entered into firm transportation contracts that require us to pay fixed amounts of money to our counterparties regardless of quantities actually shipped, processed, or gathered. If we are unable to deliver the necessary quantities of natural gas to our counterparties, our results of operations and liquidity could be adversely affected.

As of December 31, 2012, we were contractually committed to deliver 1,515 Bcf of natural gas and 36 MMBbls of oil pursuant to contracts expiring at various dates through 2023. We may enter into additional firm transportation agreements as our development of our shale plays, including the Eagle Ford and Haynesville shales, expand. At the current time, we do not have enough proved developed reserves to offset these contractual liabilities, but we intend to develop reserves that will exceed the commitments and therefore do not expect any shortfalls. We expect our production volumes, as well as that of our competitors, to increase significantly in the Eagle Ford shale. The use of firm transportation commitments gives us the strategic advantage of priority space in a transportation pipeline. In the event we encounter delays in drilling and completing our wells or otherwise due to construction, interruptions of operations, or delays in connecting new volumes to gathering systems or pipelines for an extended period of time, the requirements to pay for quantities not delivered could have a material impact on our results of operations and liquidity.

Future crude oil, natural gas, and NGL price declines or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our crude oil and natural gas properties. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If commercial quantities of hydrocarbons are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our crude oil, natural gas, and NGL properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net revenues, we generally must write down the costs of each depletion pool to the estimated discounted future net cash flows of that depletion pool. Unproved properties are evaluated at the lower of cost or fair market value. We incurred an impairment of proved property and impairment of unproved properties totaling $208.9 million and $16.3 million, respectively, during 2012, $219.0 million and $7.4 million, respectively, during 2011, and $6.1 million and $2.0 million, respectively, during 2010. Significant further declines in crude oil, natural gas, or NGL prices in the future or unsuccessful exploration efforts could cause further impairment write-downs of capitalized costs.

We review the carrying value of our properties for indicators of impairment on a quarterly basis using the prices in effect as of the end of each quarter. Once incurred, a write-down of oil and natural gas properties cannot be reversed at a later date, even if crude oil, natural gas, or NGL prices increase.

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Lower crude oil, natural gas, or NGL prices could limit our ability to borrow under our credit facility.

Our credit facility has a current commitment amount of $1.0 billion, subject to a borrowing base that the lenders redetermine semi-annually based largely on the bank group's assessment of the value of our crude oil, natural gas, and NGL properties, which in turn is impacted by crude oil, natural gas, and NGL prices. The current borrowing base under our credit facility is $1.55 billion. Declines in crude oil, natural gas, or NGL prices in the future could limit our borrowing base and reduce the amount we can borrow under our credit facility. Additionally, divestitures of properties could result in a reduction of our borrowing base.

Our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt.

As of December 31, 2012, we had $350.0 million of long-term senior unsecured debt outstanding relating to our 6.625% Senior Notes due 2019 (the "2019 Notes") that we issued on February 7, 2011; $350.0 million of long-term senior unsecured debt outstanding relating to our 6.50% Senior Notes due 2021 (the "2021 Notes") that we issued on November 8, 2011; and $400.0 million of long-term senior unsecured debt outstanding relating to our 6.50% Senior Notes due 2023 (the "2023 Notes") that we issued on June 29, 2012, (collectively referred to as our "Senior Notes"); and $340.0 million of outstanding borrowings under our secured credit facility. We had three outstanding letters of credit in the aggregate amount of $808,000, (which reduce the amount available for borrowings under the facility on a dollar-for-dollar basis), resulting in $659.2 million of available debt capacity under our credit facility, assuming the borrowing conditions under this facility will be met. Our long-term debt represented 50 percent of our total book capitalization as of December 31, 2012.

Our indebtedness could have important consequences for our operations, including:

- making it more difficult for us to obtain additional financing in the future for our operations and potential acquisitions, working capital requirements, capital expenditures, debt service, or other general corporate requirements;
- requiring us to dedicate a substantial portion of our cash flows from operations to the repayment of our debt and the service of interest costs associated with our debt, rather than to productive investments;
- limiting our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making acquisitions, and paying dividends;
- placing us at a competitive disadvantage compared to our competitors that have less debt; and
- making us more vulnerable in the event of adverse economic or industry conditions or a downturn in our business.

Our ability to make payments on our debt and to refinance our debt and fund planned capital expenditures will depend on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory, and other factors that are beyond our control. If our business does not generate sufficient cash flow from operations or future sufficient borrowings are not available to us under our credit facility or from other sources, we might not be able to service our debt or fund our other liquidity needs. If we are unable to service our debt, due to inadequate liquidity or otherwise, we may have to delay or cancel acquisitions, defer capital expenditures, sell equity securities, divest assets, or restructure or refinance our debt. We might not be able to sell our equity securities, sell our assets, or restructure or refinance our debt on a timely basis or on satisfactory terms or at all. In addition, the terms of our existing or future debt agreements, including our existing and future credit agreements, may prohibit us from pursuing any of these alternatives. Further, changes in the credit ratings of our debt may negatively affect the cost, terms, conditions, and availability of future financing.

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Our debt agreements, including the agreement governing our credit facility and the indentures governing the 2019 Notes, 2021 Notes, and 2023 Notes, permit us to incur additional debt in the future, subject to compliance with restrictive covenants under those agreements. In addition, entities we may acquire in the future could have significant amounts of debt outstanding that we could be required to assume, and in some cases accelerate repayment thereof, in connection with the acquisition, or we may incur our own significant indebtedness to consummate an acquisition.
As discussed above, our credit facility is subject to periodic borrowing base redeterminations. We could be forced to repay a portion of our bank borrowings in the event of a downward redetermination of our borrowing base, and we may not have sufficient funds to make such repayment at that time. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowing base or arrange new financing, we may be forced to sell significant assets.

The agreements governing our debt contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.

Our debt agreements contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under our credit facility is subject to compliance with certain financial covenants, including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest, taxes, depreciation, amortization, and exploration expense of no greater than 4.0 to 1.0, and (ii) maintenance of an adjusted current ratio of no less than 1.0 to 1.0, each as defined in our credit facility. Our credit facility also requires us to comply with certain financial covenants, including requirements that we maintain certain levels of stockholders' equity and limit our annual cash dividends to no more than $50.0 million. These restrictions on our ability to operate our business could seriously harm our business by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

The respective indentures governing the 2019 Notes, 2021 Notes, and 2023 Notes also contain covenants that, among other things, limit our ability and the ability of our subsidiaries to:

- incur additional debt;
- make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem, or retire capital stock;
- sell assets, including capital stock of our subsidiaries;
- restrict dividends or other payments of our subsidiaries;
- create liens that secure debt;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all or a portion of our indebtedness. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

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We are subject to operating and environmental risks and hazards that could result in substantial losses.
Crude oil and natural gas operations are subject to many risks, including human error and accidents that could cause personal injury, death and property damage, well blowouts, craterings, explosions, uncontrollable flows of crude oil, natural gas and associated liquids or well fluids, migration of fracture fluids into surrounding groundwater, spills or releases from facilities and equipment used to deliver these materials, spills or releases of brine or other produced or flowback water, subsurface conditions that prevent us from stimulating the planned number of stages, accessing the entirety of the wellbore with our tools during completion, or removing fracturing materials from the wellbore to allow production to begin, fires, adverse weather such as hurricanes in the South Texas & Gulf Coast region, freezing conditions in the Williston Basin of our Rocky Mountain region, floods, droughts, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas such as hydrogen sulfide, and other environmental risks and hazards. If any of these types of events occurs, we could sustain substantial losses. Furthermore, if we experience any of the problems with well stimulation and completion activities referenced above, such as hydraulic fracturing, our ability to explore for and produce crude oil, natural gas, or NGLs may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of the need to shutdown, abandon and relocate drilling operations, the need to sample, test and monitor drinking water in particular areas and to provide filtration or other drinking water supplies to users of water supplies that may have been impacted or threatened by potential contamination from fracturing fluids, the need to modify drill sites to ensure there are no spills or releases off-site and to investigate and/or remediate any spills or releases that might have occurred, and suspension of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in our operations due to our current and past generation, handling and disposal of materials, including solid and hazardous wastes and petroleum hydrocarbons. We may incur joint and several, strict liability under applicable United States federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from our leased or owned properties, some of which have been used for natural gas and oil exploration and production activities for a number of years, often by third parties not under our control. For our non-operated properties, we are dependent on the operator for operational and regulatory compliance, and could be subject to liabilities in the event of non-compliance. These properties and the wastes disposed thereon or away from could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including the CERCLA or the Superfund law, the RCRA, the Clean Water Act, the CAA, the OPA, and analogous state laws. Under any implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damage allegedly caused by the release of petroleum hydrocarbons or other wastes into the environment. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.
We maintain insurance against some, but not all, of these potential risks and losses. We have significant but limited coverage for sudden environmental damage. We do not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damage or insurance coverage for environmental damage that occurs over time is available at a reasonable cost. In addition, pollution and environmental risks generally are not fully insurable. Further, we may elect not to obtain other insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks to which we are subject. Accordingly, we may be subject to liability or may lose substantial assets in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, we could suffer a material loss.

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Following the severe Atlantic hurricanes in 2004, 2005, and 2008, the insurance markets suffered significant losses. As a result, insurance coverage for wind storms has become substantially more expensive, and future availability and costs of coverage are uncertain.

Our operations are subject to complex laws and regulations, including environmental regulations that result in substantial costs and other risks.

Federal, state, tribal, and local authorities extensively regulate the oil and natural gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing or marketing of crude oil, natural gas and NGL production. Noncompliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead to substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations and may also result in the suspension or termination of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, and abandon wells and related facilities and, in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for and the production of crude oil, natural gas, and NGLs, including the permit and bonding requirements of drilling wells, the spacing of wells, the unitization or pooling of interests in crude oil and natural gas properties, rights-of-way and easements, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, and restoration standards, oil and gas operations, and restoration. Public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit or right-of-way grant or impose conditions of approval to mitigate potential environmental impacts, which could, in either case, negatively affect our ability to explore or develop certain properties. Federal authorities also may require any of our ongoing or planned operations on federal leases to be delayed, suspended, or terminated. Any such delay, suspension, or termination could have a materially adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, tribal and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, including the designation of previously unprotected wildlife or plant species as threatened or endangered in areas we operate, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several, strict liability under federal, state, and tribal environmental laws for noise emissions and for discharges of crude oil, natural gas, and associated liquids or other pollutants into the air, soil, surface water, or groundwater. We could be required to spend substantial amounts on investigations, litigation, and remediation for these emissions and discharges and other compliance issues. Any unpermitted release of petroleum or other pollutants from our operations could result not only in cleanup costs, but also natural resources, real or personal property and other compensatory damages and civil and criminal liability. The listing of additional wildlife or plant species as federally endangered or threatened could result in limitations on exploration and production activities in certain locations. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a materially adverse effect on us.

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

Operations in certain of our regions, such as our Rocky Mountain and Permian regions, are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife or plant species. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during

limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Wildlife seasonal restrictions may limit access to federal leases or across federal lands. Possible restrictions may include seasonal restrictions in greater sage-grouse habitat during breeding and nesting seasons, within a certain distance of active raptor nests during fledging, and in big game winter or parturition ranges during winter or calving seasons. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas and associated liquids from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Eagle Ford shale of south Texas, and the Bakken/Three Forks formations in North Dakota. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving the use of diesel in the fluid system under SDWA and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress during prior sessions and is likely to be introduced during the 113th Congress, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. If hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit or disclosure requirements or operational restrictions and also to associated permitting delays, litigation risk, and potential cost increases.

Certain states that we operate in, including Pennsylvania, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas ("RCT") and the public of certain information regarding the components and volume of water used in the hydraulic fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating a review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a progress report, but no research results or findings, issued in December 2012 and a draft report of results to be issued in 2014 for independent peer review by the Science Advisory Board. In addition, the United States Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the United States Department of the Interior is developing disclosure requirements or other mandates for hydraulic fracturing on federal lands; the Department of the Interior anticipates issuing during the first quarter of 2013 a revised proposed rule relating to hydraulic fracturing activities on federal lands.

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Additionally, certain members of Congress have called upon the United States Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the United States Securities and Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the United States Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The United States Geological Survey Offices of Energy Resources Program, Water Resources and Natural Hazards and Environmental Health Offices have ongoing research projects on hydraulic fracturing. These ongoing or proposed studies, depending on their course and outcomes, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory processes.

Further, on August 16, 2012, the EPA issued final rules subjecting all oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs. The EPA rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards require the use of reduced emission completion ("REC") techniques developed in EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line beginning in January 2015. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology ("MACT") standards for those glycol dehydrators and certain storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. The EPA stated in January 2013, however, that it intends to reconsider portions of the final rule. We are currently evaluating the effect of these rules on our business.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing such activity to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. Additional legislation or regulation could also lead to operational delays or increased costs in the exploration for and production of oil, natural gas, and associated liquids, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state, or local laws, or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.

The EPA is in the process of updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act. Flowback and produced water from the hydraulic fracturing process contains total dissolved solids, including chlorides. The EPA anticipates issuing a draft criteria document in 2013.

On October 20, 2011, the EPA announced a schedule for development of standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works ("POTWs"). The regulations will be developed under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. The EPA anticipates issuing the proposed rules in 2014.

Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we depend to drill for commercial quantities of crude oil, natural gas, and associated liquids requires the use and disposal of significant quantities of water.

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Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of natural gas.
Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.
Certain United States federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

During his first term, President Obama sent to Congress a legislative package that included proposed legislation that, if enacted into law, would eliminate certain key United States federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes included, among other proposals:

- the repeal of the percentage depletion allowance for oil and natural gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain domestic production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear when or if these or similar changes will be enacted. The passage of legislation enacting these or similar changes in federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.
Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil, natural gas, and NGLs.
In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other “greenhouse gases” present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. For example, the EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other regulates the permitting and emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. In the courts, several cases are pending that may increase the risk of claims being filed against companies that have significant greenhouse gas emissions. Such cases seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property. Any laws or regulations that restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and natural gas that we produce.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil, gas, and NGLs we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition, results of operations, and cash flows. Finally, it should be noted that some scientists have predicted that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from flooding or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

Current or proposed financial legislation and rulemaking 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 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which was signed into law on July 21, 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. On October 18, 2011, the Commodities Futures Trading Commission (the "CFTC") approved regulations to set position limits for certain futures and option contracts in the major energy markets, which were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The CFTC has filed a notice of appeal with respect to this ruling. Under CFTC final rules promulgated under the Dodd-Frank Act, we believe our derivatives activity will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement. The Dodd-Frank Act may also require us to comply with margin requirements in our 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 derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act 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 our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act 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 Dodd-Frank Act was intended, in

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part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Our ability to sell crude oil, natural gas and NGLs, and/or receive market prices for our production, may be adversely affected by constraints on gathering systems, processing facilities, pipelines and other transportation systems owned or operated by others or by other interruptions.

The marketability of our crude oil, natural gas, and NGL production depends in part on the availability, proximity, and capacity of gathering systems, processing facilities, and pipeline and other transportation systems owned or operated by third parties. The lack of available capacity in these systems and facilities can result in the shutting-in of producing wells, the delay or discontinuance of development plans for our properties, or lower price realizations. Although we have some contractual control over the processing and transportation of our operated production, material changes in these business relationships could materially affect our operations. Federal and state regulation of crude oil, natural gas, and NGL production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, process, and transport crude oil, natural gas, and NGLs.

In particular, if drilling in the Eagle Ford shale, Haynesville shale, Bakken/Three Forks resource play, and Granite Wash resource play continues to be successful, the amount of crude oil, natural gas, and NGLs being produced by us and others could exceed the capacity of, and result in strains on, the various gathering and transportation systems, pipelines, processing facilities, and other infrastructure available in these areas. It will be necessary for additional infrastructure, pipelines, gathering and transportation systems and processing facilities to be expanded, built or developed to accommodate anticipated production from these areas. Because of the current economic climate, certain processing, pipeline, and other gathering or transportation projects that might be, or are being, considered for these areas may not be developed timely or at all due to lack of financing or other constraints. Capital and other constraints could also limit our ability to build or access intrastate gathering and transportation systems necessary to transport our production to interstate pipelines or other points of sale or delivery. In such event, we might have to delay or discontinue development activities or shut in our wells to wait for sufficient infrastructure development or capacity expansion and/or sell production at significantly lower prices, which would adversely affect our results of operations and cash flows. In addition, the operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state, and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations.

A portion of our production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily and adversely affect our cash flows and results of operations.

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical,

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and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our business could be negatively impacted by security threats, including cybersecurity threats, terrorism, armed conflict, and other disruptions.

As a crude oil, natural gas, and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

Cybersecurity attacks in particular are evolving and include but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for crude oil, natural gas, and NGLs, all of which could adversely affect the markets for our operations. Energy assets might be specific targets of terrorist attacks. These developments have subjected our operations to increased risk and, depending on their occurrence and ultimate magnitude, could have a material adverse effect on our business.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly, which may result in losses for investors.

From January 1, 2012, to February 14, 2013, the closing daily sale price of our common stock as reported by the New York Stock Exchange ranged from a low of $41.80 per share in August 2012 to a high of $83.35 per share in February 2012. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in crude oil, natural gas, or NGL prices;
- variations in drilling, recompletion, and operating activity;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- future sales of our common stock; and
- changes in the national and global economic outlook.

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We may not meet the expectations of our stockholders and/or of securities analysts at some time in the future, and our stock price could decline as a result.

Our certificate of incorporation and by-laws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment.

Our certificate of incorporation and by-laws contain provisions that may have the effect of delaying or preventing a change of control. These provisions, among other things, provide for non-cumulative voting in the election of members of the Board of Directors and impose procedural requirements on stockholders who wish to make nominations for the election of directors or propose other actions at stockholder meetings. These provisions, alone or in combination with each other, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

Shares eligible for future sale may cause the market price of our common stock to drop significantly, even if our business is doing well.

The potential for sales of substantial amounts of our common stock in the public market may have a materially adverse effect on our stock price. As of February 14, 2013, 66,153,847 shares of our common stock were freely tradable without substantial restriction or the requirement of future registration under the Securities Act of 1933. Also as of that date, options to purchase 257,180 shares of our common stock were outstanding, all of which were exercisable. These options are exercisable at prices ranging from $12.53 to $20.87 per share. In addition, restricted stock units (“RSUs”) providing for the issuance of up to a total of 493,968 shares of our common stock and 898,145 performance share units were outstanding. Performance share units are structurally the same as the previously granted Performance Share Awards or (“PSAs”) (collectively known as “Performance Share Units” or “PSUs”). The PSUs represent the right to receive, upon settlement of the PSUs after the completion of a three-year performance period, a number of shares of our common stock that may be from zero to two times the number of PSUs granted, depending on the extent to which the underlying performance criteria have been achieved and the extent to which the PSUs have vested. As of February 14, 2013, there were 66,205,901 shares of our common stock outstanding, which is net of 50,581 treasury shares.

We may not always pay dividends on our common stock.

Payment of future dividends remains at the discretion of our Board of Directors, and will continue to depend on our earnings, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to a covenant in our credit facility limiting our annual cash dividends to no more than $50.0 million, and to covenants in the indentures for our 2019 Notes, 2021 Notes, and 2023 Notes that limit our ability to pay dividends beyond a certain amount. Our Board of Directors may determine in the future to reduce the current semi-annual dividend rate of $0.05 per share, or discontinue the payment of dividends altogether.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the filing date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows.

We were a defendant in litigation, captioned W.H. Sutton, et al. vs. St. Mary Land & Exploration Co., et al., wherein the plaintiffs claimed an aggregate overriding royalty interest of 7.46875 percent in production from approximately 22,000 of our net acres in the Eagle Ford shale play in South Texas. The plaintiffs sought to quiet title to their claimed overriding royalty interest and to recover unpaid overriding royalty interest proceeds allegedly due. We believed that the claimed overriding royalty interest had been terminated under the governing agreements and the applicable law, and contested the plaintiffs' claims. Both parties filed motions for summary judgment, and on February 8, 2011, the District Court in Webb County, Texas, issued an order granting plaintiffs' motion for summary judgment and denying our motion for summary judgment. On September 30, 2011, the District Court entered final judgment for the plaintiffs and awarded then current damages of approximately $5.1 million, which included prejudgment interest. The District Court also awarded attorneys fees and costs to the plaintiffs. We appealed the District Court's judgment and obtained a stay pending appeal that prevented the plaintiffs from executing on the judgment.

On May 23, 2012, the Fourth Court of Appeals for the State of Texas delivered its opinion in this matter, which reversed the summary judgment granted to the plaintiffs by the District Court and rendered judgment that the plaintiffs take nothing. Accordingly, based on the judgment of the Fourth Court of Appeals, the plaintiffs are not entitled to their claimed 7.46875 percent overriding royalty interest, nor are they entitled to the claimed damages related to the overriding royalty interest, attorneys fees or costs. The plaintiffs petitioned the Supreme Court of Texas for a review of the judgment of the Fourth Court of Appeals. The Supreme Court of Texas denied this petition for review on February 15, 2013, and as a result, the decision of the Fourth Court of Appeals is dispositive and its dismissal of the plaintiffs' claims is final.

We also filed a declaratory judgment action in Webb County, Texas, captioned SM Energy Company vs. W.H. Sutton, et al., seeking a judgment declaring that the lease at issue in W.H. Sutton, et al. vs. St. Mary Land & Exploration Co., et al. had terminated with respect to the remaining 18,000 acres, based upon a failure of continuous development, and that any overriding royalty interest claimed by the defendants has been extinguished. On September 19, 2012, the District Court in Webb County, Texas, granted our motion for summary judgment, concluding that the defendants' claims for any overriding royalty interest had been extinguished. The plaintiffs filed their notice of appeal to the Fourth Court of Appeals on November 15, 2012, but due to the numerous requests for an extension, have not yet filed their brief. We will continue to contest this litigation.

We, and our working interest partners, filed an action against Endeavour Operating Corporation ("Endeavour") in Harris County, Texas, captioned SM Energy Company, et al. v. Endeavour Operating Corporation, seeking an order requiring Endeavour to honor its obligations to consummate the purchase of certain assets located in Pennsylvania, or in the alternative, for damages. We are required to take reasonable measures to attempt to mitigate our potential losses, and during 2012 we initiated efforts to remarket such assets. If we are successful in such efforts and complete a sale of these assets for less than the $110 million ($80 million of which is attributable to our interest) Endeavour agreed to pay to us and our working interest partners, we will continue to prosecute this action to recover any such deficiency and any amounts expended in our efforts to remarket the assets, and to obtain any other relief to which we are entitled. As of the filing date of this report, we have no commitment from another party to purchase these assets.

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On January 27, 2011, Chieftain Royalty Company (“Chieftain”) filed a Class Action Petition against us in the District Court of Beaver County, Oklahoma, claiming damages related to royalty valuation on all of our Oklahoma wells. These claims include breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. We removed this lawsuit to the United States District Court for the Western District of Oklahoma on February 22, 2011. We have responded to the petition and denied the allegations. The court has not yet ruled on Chieftain's motion to certify the putative class, and has stayed any such ruling until the United States Court of Appeals for the Tenth Circuit issues its ruling on class certification in two similar royalty class action lawsuits, where the defendants have appealed such certification. The opinion from the Tenth Circuit is expected during the summer of 2013. We believe we properly valued and paid royalty under Oklahoma law and have and will continue to vigorously defend this case.

ITEM 4. MINE SAFETY DISCLOSURES

These disclosures are not applicable to us.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information. Our common stock is currently traded on the New York Stock Exchange under the ticker symbol "SM". The following table presents the range of high and low intraday sales prices per share for the indicated quarterly periods in 2012 and 2011, as reported by the New York Stock Exchange:

Quarter Ended	High	Low
December 31, 2012	$62.09	$45.25
September 30, 2012	$59.39	$39.44
June 30, 2012	$71.81	$43.12
March 31, 2012	$84.40	$69.40
December 31, 2011	$88.50	$53.45
September 30, 2011	$85.55	$60.52
June 30, 2011	$78.55	$61.37
March 31, 2011	$75.00	$54.59

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2007, and ending on December 31, 2012, with the cumulative total returns of the Dow Jones U.S. Exploration and Production Board Index, and the Standard & Poor's 500 Stock Index.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURNS

The preceding information under the caption Performance Graph shall be deemed to be furnished, but not filed with the Securities and Exchange Commission.

Holders. As of February 14, 2013, the number of record holders of SM Energy's common stock was 88. Based upon inquiry, management believes that the number of beneficial owners of our common stock is approximately 35,200.

Dividends. We have paid cash dividends to our stockholders every year since 1940. Annual dividends of $0.05 per share were paid in each of the years 1998 through 2004. Annual dividends of $0.10 per share were paid in 2005 through 2012. We expect that our practice of paying dividends on our common stock will continue,

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although the payment of future dividends will continue to depend on our earnings, cash flow, capital requirements, financial condition, and other factors, including the discretion of our Board of Directors. In addition, the payment of dividends is subject to covenants in our credit facility that limit our annual dividend payment to no more than $50.0 million per year. We are also subject to certain covenants under our 2019 Senior Notes, our 2021 Senior Notes, and our 2023 Senior Notes that restrict certain payments, including dividends; provided, however, the first $6.5 million of dividends paid each year are not restricted by this covenant. Based on our current performance, we do not anticipate that these covenants will restrict future annual dividend payments of $0.10 per share of common stock. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $6.5 million in 2012 and $6.4 million in 2011.

Restricted Shares. We have no restricted shares outstanding as of December 31, 2012, aside from Rule 144 restrictions on shares held by insiders and shares issued to members of the Board of Directors under our Equity Incentive Compensation Plan ("Equity Plan").

Purchases of Equity Securities by the Issuer and Affiliated Purchasers. The following table provides information about purchases by the Company and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the indicated quarters and year ended December 31, 2012, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

ISSUER PURCHASES OF EQUITY SECURITIES

	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program(2)
January 1, 2012 – March 31, 2012	176	$79.93	—	3,072,184
April 1, 2012 - June 30, 2012	—	$—	—	3,072,184
July 1, 2012 - September 30, 2012	456,227	$47.32	—	3,072,184
October 1, 2012 - October 31, 2012	—	$—	—	3,072,184
November 1, 2012 - November 30, 2012	162	$49.43	—	3,072,184
December 1, 2012 - December 31, 2012	158	$53.92	—	3,072,184
Total October 1, 2012 - December 31, 2012	320	$51.66	—	3,072,184
Total	456,723	$47.34	—	3,072,184

(1) All shares purchased in 2012 were to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying RSUs and PSUs delivered under the terms of grants under the Equity Plan.

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, subject to the approval of our Board of Directors, we may repurchase up to 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, or borrowings under our credit facility. The stock repurchase program may be suspended or discontinued at any time. Please refer to Dividends above for a description of our dividend limitations.

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected supplemental financial and operating data for us as of the dates and periods indicated. The financial data for each of the five years presented were derived from our consolidated financial statements. The following data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of this report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this report.

	Years Ended December 31,				
	2012	2011	2010	2009	2008
	(in millions, except per share data)				
Total operating revenues	$1,505.1	$1,603.3	$1,092.8	$832.2	$1,301.3
Net income (loss)	$(54.2)	$215.4	$196.8	$(99.4)	$87.3
Net income (loss) per share:					
Basic	$(0.83)	$3.38	$3.13	$(1.59)	$1.40
Diluted	$(0.83)	$3.19	$3.04	$(1.59)	$1.38
Total assets at year-end	$4,199.5	$3,799.0	$2,744.3	$2,360.9	$2,697.2
Long-term debt:					
Line of credit	$340.0	$—	$48.0	$188.0	$300.0
3.50% Senior Convertible Notes, net of debt discount	$—	$285.1	$275.7	$266.9	$258.7
6.625% Senior Notes due 2019	$350.0	$350.0	$—	$—	$—
6.50% Senior Notes due 2021	$350.0	$350.0	$—	$—	$—
6.50% Senior Notes due 2023	$400.0	$—	$—	$—	$—
Cash dividends declared and paid per common share	$0.10	$0.10	$0.10	$0.10	$0.10

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Supplemental Selected Financial and Operations Data

	For the Years Ended December 31, 2012	2011	2010	2009	2008
Balance Sheet Data (in millions)					
Total working capital (deficit)	$(201.0)	$(42.6)	$(227.4)	$(87.6)	$15.2
Total stockholders' equity	$1,414.5	$1,462.9	$1,218.5	$973.6	$1,162.5
Weighted-average common shares outstanding (in thousands)					
Basic	65,138	63,755	62,969	62,457	62,243
Diluted	65,138	67,564	64,689	62,457	63,133
Reserves					
Oil (MMBbl)	92.2	71.7	57.4	53.8	51.4
Gas (Bcf)	833.4	664.0	640.0	449.5	557.4
NGLs (MMBbl)	62.3	27.5	—	—	—
BCFE	1,760.6	1,259.2	984.5	772.2	865.5
Production and Operational (in millions)					
Oil, gas, and NGL production revenues	$1,473.9	$1,332.4	$836.3	$616.0	$1,259.4
Oil, gas, and NGL production expenses	$391.9	$290.1	$195.1	$206.8	$271.4
DD&A	$727.9	$511.1	$336.1	$304.2	$314.3
General and administrative	$119.8	$118.5	$106.7	$76.0	$79.5
Production Volumes					
Oil (MMBbl)	10.4	8.1	6.4	6.3	6.6
Gas (Bcf)	120.0	100.3	71.9	71.1	74.9
NGLs (MMBbl)	6.1	3.5	—	—	—
BCFE	218.9	169.7	110.0	109.1	114.6
Realized price					
Oil (per Bbl)	$85.45	$88.23	$72.65	$54.40	$92.99
Gas (per Mcf)	$2.98	$4.32	$5.21	$3.82	$8.60
NGL (per Bbl)	$37.61	$53.32	$—	$—	$—
Adjusted price (net of derivative cash settlements)					
Oil (per Bbl)	$83.52	$78.89	$66.85	$56.74	$75.59
Gas (per Mcf)	$3.48	$4.80	$6.05	$5.59	$8.79
NGL (per Bbl)	$38.90	$47.90	$—	$—	$—
Expense per MCFE					
LOE	$0.82	$0.88	$1.10	$1.33	$1.46
Transportation	$0.63	$0.51	$0.19	$0.19	$0.19
Production taxes	$0.33	$0.32	$0.48	$0.37	$0.71
DD&A	$3.32	$3.01	$3.06	$2.79	$2.74
General and administrative	$0.55	$0.70	$0.97	$0.70	$0.69
Statement of Cash Flow Data (in millions)					
Provided by operations	$922.0	$760.5	$497.1	$436.1	$679.2
(Used in) investing	$(1,457.3)	$(1,264.9)	$(361.6)	$(304.1)	$(673.8)
Provided by (used in) financing	$422.1	$618.5	$(141.1)	$(127.5)	$(42.8)

Note: 2010 and prior NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the amounts. Please refer to additional discussion under the caption Oil, Gas, and NGL Prices in Part II, Item 7 of this report.

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ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This discussion includes forward-looking statements. Please refer to Cautionary Information about Forward-Looking Statements in Part I, Items 1 and 2 of this report for important information about these types of statements.

Overview of the Company

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. Our assets include leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays, as well as exposure to the Granite Wash play and emerging oil-focused plays in the Permian Basin. We have built a portfolio of onshore properties in the contiguous United States primarily through early entry into existing and emerging resource plays. This portfolio is comprised of properties with established production and reserves, prospective drilling opportunities, and unconventional resource prospects. We believe our strategy provides for stable and predictable production and reserve growth. Furthermore, by entering these plays early, we believe we can capture larger resource potential at a lower cost.

Our principal business strategy is to focus on the early capture of resource plays in order to create and then enhance value for our shareholders while maintaining a strong balance sheet. We strive to leverage industry-leading exploration and leasehold acquisition teams to quickly acquire and test new resource play concepts at a reasonable cost. Once we have identified potential value through these efforts, our goal is to develop such potential through top-tier operational and project execution and to mitigate our risks by selectively divesting of certain assets when deemed appropriate by us. We continually examine our portfolio for opportunities to improve the quality of our asset base in order to optimize our returns and preserve our financial strength.

In 2012 we had the following financial and operational results:

- At year-end 2012, we had estimated proved reserves of 1,760.6 BCFE (293.4 MMBOE), of which 53 percent were liquids (oil and NGLs) and 57 percent was characterized as proved developed. We added 900.2 BCFE from our drilling program, the majority of which related to our activity in the Eagle Ford shale in South Texas and the Bakken/Three Forks plays in North Dakota. We had negative price revisions that decreased our estimated proved reserves by 72.7 BCFE primarily due to gas weighted projects in our South Texas & Gulf Coast and Mid-Continent regions that do not generate positive cash flow utilizing historical 12-month average benchmark pricing required by the SEC. The prices used in the calculation of proved reserve estimates as of December 31, 2012, were $94.71 per Bbl, $2.76 per MMBtu, and $45.65 per Bbl, for oil, gas, and NGLs, respectively. These prices were two percent, 33 percent, and 23 percent lower for oil, gas, and NGLs, respectively, than the prices used at year-end 2011. We had downward engineering revisions of 49.2 BCFE related primarily to Eagle Ford shale proved undeveloped locations as well as downward engineering revisions of Wolfberry assets in our Permian region. Additionally, we removed 42.7 BCFE of proved undeveloped reserves primarily in the Woodford shale due to low natural gas prices and as a result of the five-year limitation on the number of years proved undeveloped reserves may remain on the books without being developed. Please refer to the caption Proved Undeveloped Reserves under the section Reserves included in Part I, Items 1 and 2 of this report for additional discussion. We had immaterial acquisitions of 1.6 BCFE, and we divested of 16.9 BCFE of proved reserves during the year related to non-core assets located primarily in our Rocky Mountain and Mid-Continent regions.

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- The PV-10 value of our estimated proved reserves was $3.8 billion as of December 31, 2012, compared with $3.5 billion as of December 31, 2011. The after tax value, represented by the standardized measure calculation, was $3.0 billion as of December 31, 2012 compared with $2.6 billion as of December 31, 2011. The standardized measure calculation is presented in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report. A reconciliation between the PV-10 reserve value and the after tax value is shown under Reserves in Part I, Items 1 and 2 of this report.
- We had record production in 2012. Our average daily production in 2012 was 28.3 MBbl of oil, 328.0 MMcf of gas, and 16.7 MBbl of NGLs, for an average equivalent production rate of 598.2 MMCFE, compared with 465.0 MMCFE in 2011, an increase of 29 percent year-over-year. Please refer to the caption Production Results below for additional discussion.
- We recorded a net loss of $54.2 million, or a loss of $0.83 per diluted share, for the year ended December 31, 2012, due to an impairment of proved properties. This compares with net income of $215.4 million, or $3.19 per diluted share, for the year ended December 31, 2011. Please refer to the caption Comparison of Financial Results and Trends Between 2012 and 2011 below for additional discussion regarding the components of net income (loss) and 2012 Highlights for additional discussion on impairment of proved properties.
- We had record cash flow provided by operating activities of $922.0 million for the year ended December 31, 2012, compared with $760.5 million for the year ended December 31, 2011, which was an increase of 21 percent year-over-year. Please refer to Analysis of cash flow changes between 2012 and 2011 below for additional discussion.
- Costs incurred for oil and gas producing activities for the year ended December 31, 2012, were $1.7 billion, compared with $1.6 billion for the same period in 2011. Please refer to the caption Costs Incurred in Oil and Gas Producing Activities below for additional discussion.
- EBITDAX, a non-GAAP financial measure, for the year ended December 31, 2012, was $1.0 billion, compared with $886.6 million for the same period in 2011. Please refer to the caption Non-GAAP Financial Measures below for additional discussion, including our definition of EBITDAX and reconciliations of our GAAP net income (loss) and net cash provided by operating activities to EBITDAX.

Reserve Replacement, Finding and Development Costs, and Growth

Like all oil and gas exploration and production companies, we face the challenge of growing proved reserves. An exploration and production company depletes part of its asset base with each unit of oil, gas, or NGL it produces. Our future growth will depend on our ability to organically and economically add reserves in excess of production.

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The following table provides various reserve replacement and finding and development cost metrics for the year ended December 31, 2012:

	Reserve Replacement Percentage				Finding and Development Cost per MCFE (1)	
	Excluding Divestitures		Including Divestitures		Excluding Divestitures	Including Divestitures
Drilling, excluding revisions	411	%	403	%	$1.74	$1.77
Drilling, including revisions	336	%	328	%	$2.13	$2.18
Drilling and acquisitions, excluding revisions	412	%	404	%	$1.74	$1.78
Drilling and acquisitions, including revisions	337	%	329	%	$2.13	$2.18
Reserve Acquisitions	1	%	N/M		$3.59	N/M
All-in	337	%	329	%	$2.29	$2.34

* N/M – Percentage or amount, as applicable, is not meaningful.
(1) Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement for discussion on how we are being carried on 90 percent of certain drilling and completion costs.

The following table provides average reserve replacement and finding and development cost metrics for the three-year period ended December 31, 2012:

	Reserve Replacement Percentage				Finding and Development Cost per MCFE (1)	
	Excluding Divestitures		Including Divestitures		Excluding Divestitures	Including Divestitures
Drilling, excluding revisions	363	%	324	%	$2.15	$2.41
Drilling, including revisions	337	%	298	%	$2.31	$2.62
Drilling and acquisitions, excluding revisions	363	%	324	%	$2.15	$2.41
Drilling and acquisitions, including revisions	338	%	298	%	$2.31	$2.62
Reserve Acquisitions	N/M		N/M		$3.52	N/M
All-in	338	%	298	%	$2.45	$2.77

* N/M – Percentage or amount, as applicable, is not meaningful.
(1) Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement for discussion on how we are being carried on 90 percent of certain drilling and completion costs.

Our challenge is to grow net asset value per share, which we believe drives appreciation in our stock price over the long term. To accomplish this, we believe it is important to organically and economically replace annual production with new reserves. We believe annual reserve replacement percentage and finding and development costs are important analytical measures that are widely used by investors and industry peers in evaluating and comparing the performance of oil and gas companies. While single-year measurements have some meaning in terms of a trend, we believe aberrations, causing both positive and negative results, will occur over short intervals of time. The information used to calculate the above reserve replacement and finding and development cost metrics is included in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report. For additional information about these metrics, see the reserve replacement and finding and development cost terms in the Glossary of Oil and Gas Terms at the end of Part I, Items 1 and 2 of this report.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, gas, and NGL production, which can fluctuate dramatically. We sell the majority of our natural gas under contracts using first-of-the-month index pricing, which means gas produced in a given month is sold at the first-of-the-month price regardless of the spot price on the day the gas is produced. For assets where high BTU gas is sold

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at the wellhead, we also receive additional value for the high energy content contained in the gas stream. Our NGL production is generally sold using contracts paying us a monthly average of the posted OPIS daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil and condensate are sold using contracts paying us either the average of the NYMEX WTI daily settlement price or the average of alternative posted prices for the periods in which the product is produced, adjusted for quality, transportation, and location differentials.

Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. As a result, we reported realized prices for our natural gas production for periods through December 31, 2010, that were higher than industry benchmarks due to the price uplift associated with incremental value contained in the higher BTU content of our produced gas stream. Beginning in 2011, we changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Projected rapid production growth from our NGL-rich assets associated with plant product sales contracts necessitated a change in our reporting of production volumes. Our 2010 production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the NGL volumes produced in that period.

The following table is a summary of commodity price data for the years ended December 31, 2012, 2011, and 2010:

	For the Years Ended December 31,		
	2012	2011	2010
Crude Oil (per Bbl):			
Average NYMEX price	$94.10	$95.05	$79.51
Realized price	$85.45	$88.23	$72.65
Natural Gas:			
Average NYMEX price (per MMBtu)	$2.75	$4.00	$4.37
Realized price (per Mcf)	$2.98	$4.32	$5.21
NGLs (per Bbl):			
Average OPIS price	$44.91	$59.47	$34.61
Realized price	$37.61	$53.32	N/A

Note: 2010 NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of NGL volumes. Please refer to additional discussion above. Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent the Company’s product mix for NGL production. The Company's actual product mix is reflected in actual prices received for NGLs produced.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil will likely continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly in the Middle East. The relative strength of the U.S. dollar compared to other currencies could also affect the price of oil. The supply of NGLs in the U.S. is expected to continue to grow in the near term as a result of the number of industry participants targeting projects that produce these products. The pace of NGL production is growing faster than the capacity to process or consume NGLs, which will likely negatively impact pricing in the near term. The prices of several of the specific NGL products correlate to the price of oil and accordingly are likely to directionally follow that market. Gas prices have been under downward pressure for several years due to market oversupply resulting from continued high levels of natural gas production and insufficient demand for natural gas as a result of tepid economic growth, although gas prices increased moderately in the last half of 2012. The 12-month strip prices for NYMEX WTI oil, NYMEX

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Henry Hub gas, and OPIS NGLs (same product mix as discussed above) as of December 31, 2012, were $93.19 per Bbl of oil, $3.60 per MMBtu of gas, and $41.20 per Bbl of NGLs, respectively. Comparable prices as of February 14, 2013, were $98.38 per Bbl, $3.51 per MMBtu, and $41.03 per Bbl, respectively.

While changes in quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products. Consistent with all prior periods reported, our realized prices shown in the table above do not include the impact of cash settlements from derivative contracts.

Derivative Activity

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The amount of our production covered by derivatives is driven by the amount of debt on our balance sheet and the level of capital commitments and long-term obligations we have in place. With our current derivative contracts, we believe we have established a base cash flow stream for our future operations and have partially reduced our exposure to volatility in commodity prices. We utilize swaps as well as costless collars for a portion of our derivatives since collars allow us to participate in some of the upward movements in oil, gas, and NGL prices while also setting a price floor for a portion of our production. Please refer to Note 10 – Derivative Financial Instruments in Part II, Item 8 of this report for additional information regarding our oil, gas, and NGL derivatives, and the caption, Summary of Oil, Gas, and NGL Derivative Contracts in Place, below.

The following table presents a reconciliation from our realized price to our adjusted price for the commodities indicated, including the effects of derivative cash settlements, for 2012, 2011, and 2010:

	For the Years Ended December 31,		
	2012	2011	2010
Crude Oil (per Bbl):			
Realized price	$85.45	$88.23	$72.65
Less the effects of derivative cash settlements	(1.93)	(9.34)	(5.80)
Adjusted price, including the effects of derivative cash settlements	$83.52	$78.89	$66.85
Natural Gas (per Mcf):			
Realized price	$2.98	$4.32	$5.21
Add the effects of derivative cash settlements	0.50	0.48	0.84
Adjusted price, including the effects of derivative cash settlements	$3.48	$4.80	$6.05
Natural Gas Liquids (per Bbl):			
Realized price	$37.61	$53.32	$—
Add (less) the effects of derivative cash settlements	1.29	(5.42)	—
Adjusted price, including the effects of derivative cash settlements	$38.90	$47.90	$—

Note: 2010 NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes. Please refer to additional discussion under the caption Oil, Gas, and NGL Prices above.

The Dodd-Frank Act included provisions requiring over-the-counter derivative transactions to be executed through an exchange or centrally cleared. On July 10, 2012, the CFTC and the SEC adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms and determine what types of transactions will be subject to heightened scrutiny under the Dodd-Frank Act swap rules. The issuance of these final rules also triggers compliance dates for a number of other final Dodd-Frank Act rules, including new rules proposed by the CFTC governing margin requirements for uncleared swaps entered into by non-bank swap entities, and new rules proposed

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by U.S. banking regulators regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect on our business of these new rules and any additional regulations is currently uncertain. Under CFTC rules we believe our derivative activity will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement. However, we are not certain whether the provisions of the final rules and regulations will exempt us from the requirements to post margin in connection with commodity price risk management activities. Final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

2012 Highlights

Operational Activities. We operated between 15 and 18 drilling rigs company-wide for most of 2012. The primary focus of our operated drilling activity this year was oil and NGL-rich gas projects. We also participated in non-operated drilling activity primarily in oil and NGL-rich plays.

In our Eagle Ford shale program in South Texas, we operated six rigs throughout most of 2012 until releasing one of our operated rigs at the end of the third quarter due to increased drilling rig efficiencies. We focused our drilling in areas with higher BTU gas content and condensate yields. We believe we have secured most of the requisite services, such as gas pipeline takeaway capacity and drilling and completion services, to support our current development plans. We will continue to explore additional arrangements to facilitate the continued growth of our operated program. Please refer to Note 6 – Commitments and Contingencies under Part II, Item 8 of this report and Delivery Commitments and Core Operational Areas under Part I, Items 1 and 2 of this report for additional discussion concerning these agreements.

In our non-operated Eagle Ford program, the operator had nine drilling rigs and one spudder rig running throughout 2012. We expect the majority of our non-operated Eagle Ford drilling and completion costs to be funded by Mitsui over approximately the next two years under the terms of our previously announced Acquisition and Development Agreement.

We started 2012 operating three drilling rigs in our Bakken/Three Forks program in the North Dakota portion of the Williston Basin and increased to four drilling rigs in the third quarter, focusing on our Gooseneck, Raven, and Bear Den prospects. In the southern portion of our Rocky Mountain region, we operated one rig testing various formations in the Powder River Basin of Wyoming as part of our exploration program.

Effective January 1, 2012, we combined our ArkLaTex region into our Mid-Continent region, based in Tulsa, Oklahoma, for operational and reporting purposes. Throughout 2012, we operated three drilling rigs in our Granite Wash program in western Oklahoma and the Texas Panhandle, focusing primarily on the Marmaton washes due to their higher oil and NGL content. Essentially all of our acreage position in this play is held by production. We completed our operated Haynesville shale program early in the year after achieving held by production status on substantially all of our acreage.

In our Permian region, we began the year with one operated rig and increased to four during the third quarter of 2012, with two of the rigs testing the Mississippian limestone formation on our properties in the northeast Midland Basin where we have approximately 65,500 net acres. A third rig focused on the Bone Spring formation on our properties in New Mexico. Finally, the fourth rig operated in the Midland Basin, focusing on testing the Leonard shale. We added approximately 38,000 net acres to our Permian Basin Texas acreage position in 2012.

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Production Results. The table below provides a regional breakdown of our 2012 production:

	South Texas & Gulf Coast	Rocky Mountain	Mid-Continent	Permian	Total [1]
Production:					
Oil (MMBbl)	3.2	5.4	0.4	1.3	10.4
Gas (Bcf)	59.1	4.4	53.4	3.2	120.0
NGLs (MMBbl)	5.7	—	0.4	—	6.1
BCFE [1]	112.7	36.9	58.1	11.3	218.9
Avg. Daily Equivalents (MMCFE/d)	307.9	100.9	158.6	30.8	598.2
Relative percentage	51 %	17 %	27 %	5 %	100 %

(1) Totals may not sum or recalculate due to rounding.

We had record production in 2012, which was primarily driven by the development of our operated and non-operated Eagle Ford shale programs in our South Texas & Gulf Coast region. Please refer to Comparison of Financial Results and Trends between 2012 and 2011 below for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Year Ended December 31, 2012
	(in millions)
Development costs	$ 1,346.2
Exploration costs	220.9
Acquisitions	
Proved properties	5.8
Unproved properties	115.0
Total, including asset retirement obligation	$ 1,687.9

The majority of costs incurred for oil and gas producing activities during 2012 related to the development of our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program in 2013.

Impairment of Proved Properties. We recorded impairment of proved properties expense of $208.9 million for the year ended December 31, 2012, related to the write-down of our Wolfberry assets in our Permian region due to downward engineering revisions, as well as write-downs of our Haynesville shale assets due to low natural gas prices.

Divestiture Activity and Unsuccessful Sale of Properties. During 2012, we divested of various non-strategic properties located in our Rocky Mountain and Mid-Continent regions for $57.4 million in total divestiture proceeds. Additionally in 2012, we reclassified assets located in both regions that were previously classified as held for sale to assets held and used, as these assets were no longer being actively marketed, which resulted in a $33.9 million non-cash loss. Please refer to Note 3 - Divestitures and Assets Held for Sale in Part II, Item 8 of this report for additional discussion.

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Equity Compensation. During 2012, we granted 379,332 RSUs and 314,853 PSUs pursuant to our long-term equity compensation program. Additionally, we issued 929,375 shares of our common stock to settle PSU and RSU awards granted in previous years. Please refer to Note 7 - Compensation Plans in Part II, Item 8 of this report for additional discussion.

3.50% Senior Convertible Notes. In April 2012, we called for the redemption of our outstanding 3.50% Senior Convertible Notes, which triggered the conversion feature of these notes. We settled the principal amount of all converted 3.50% Senior Convertible Notes in cash with the excess value settled in shares of common stock, and settled all redeemed notes in cash. Please refer to Note 5 - Long-term Debt in Part II, Item 8 of this report for additional discussion.

2023 Notes. In June 2012, we issued $400.0 million in aggregate principal amount of 6.50% Senior Notes. The notes were issued at par and mature on January 1, 2023. We received net proceeds of $392.1 million from this issuance, which we used to pay down outstanding borrowings under our credit facility. Please refer to Note 5 - Long-term Debt in Part II, Item 8 of this report for additional discussion.

Marketing of Properties. During the second quarter of 2012, we began to re-market our Marcellus shale assets located in Pennsylvania. Please refer to Note 3 - Divestitures and Assets Held for Sale in Part II, Item 8 of this report, as well as Legal Proceedings in Part I, Item 3 of this report for additional discussion.

Credit Facility. In the third quarter of 2012, the borrowing base under our credit facility was increased by our lenders to $1.55 billion from $1.4 billion. Please refer to Overview of Liquidity and Capital Resources below for additional discussion.

Outlook for 2013

We enter 2013 with a capital program of approximately $1.5 billion, of which approximately $1.2 billion will be focused on drilling and completion activities. We expect that approximately 90 percent of our drilling budget will be spent on our operated Eagle Ford shale, Bakken/Three Forks and operated Permian programs.

In 2013, we plan to invest approximately $650 million of drilling and completion capital in our operated Eagle Ford shale play. Throughout 2013, we plan to operate five drilling rigs supported by two frac spreads, all of which will be primarily focused on pad drilling in the northern portion of our acreage position where there is a higher liquid contribution to our production mix. In 2013, our firm contracted wet gas takeaway capacity will increase with the addition of incremental capacity on existing pipelines and the addition of a third pipeline with firm transportation capacity contracted to begin in the third quarter. During 2013, we plan to continue to refine our development program and well designs to optimize well performance and capital efficiency.

In our non-operated Eagle Ford shale program, the operator is currently operating nine drilling rigs and one spudder rig. Based on the operator’s stated plans, our expectation is that the number of rigs will decrease to eight drilling rigs and one spudder rig during the year. Mitsui will carry the majority of our non-operated drilling activity through 2013, so we expect to deploy minimal drilling and completion capital in this program. Costs associated with items such as infrastructure are not carried by Mitsui, and we will be responsible for our proportionate share of those costs.

We plan to deploy $290 million of our capital budget in our Bakken/Three Forks program in the Williston Basin in 2013. Currently, we are operating four drilling rigs in this program and plan to operate an average of 3.5 drilling rigs throughout the year. Our plan with these rigs is to continue infill drilling in our three focus areas and leverage efficiencies through pad drilling.

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In our Permian program, we plan to deploy approximately $170 million of drilling and completion capital. Our program will focus two drilling rigs in our Mississippian limestone play as we continue to delineate our position of approximately 65,500 net acres. During the year, we will also continue to run an exploratory program in the Midland Basin testing various shale formations.
The remaining $90 million of our drilling and completion capital planned for this year will be deployed in our operated Granite Wash program and various other operated and non-operated programs. Our Granite Wash program will have one to two operated rigs, while the remainder of the activity will be in our exploration plays, including on our Powder River Basin acreage.
Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we intend to fund our 2013 capital program.

Financial Results of Operations and Additional Comparative Data
The table below provides information regarding selected production and financial information for the quarter ended December 31, 2012, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	December 31, 2012	September 30, 2012	June 30, 2012	March 31, 2012
	(in millions, except for production data)			
Production (BCFE)	60.7	57.0	50.6	50.7
Oil, gas, and NGL production revenue	$424.7	$373.9	$312.6	$362.6
Realized hedge gain	$1.5	$0.5	$0.2	$1.7
Gain (loss) on divestiture activity	$4.2	$(8.5)	$(24.2)	$1.5
Lease operating expense	$48.0	$46.5	$46.1	$39.4
Transportation costs	$43.0	$37.0	$30.3	$28.6
Production taxes	$20.2	$18.9	$14.7	$19.1
DD&A	$204.3	$192.4	$161.6	$169.6
Exploration	$24.2	$25.4	$22.0	$18.6
Impairment of proved properties	$170.4	$—	$38.5	$—
Abandonment and impairment of unproved properties	$5.0	$0.4	$10.7	$0.1
General and administrative	$28.4	$32.2	$31.1	$28.1
Change in Net Profits Plan liability	$(11.6)	$0.8	$(22.1)	$3.9
Unrealized and realized derivative (gain) loss	$(15.6)	$55.9	$(98.1)	$2.2
Net income (loss)	$(67.1)	$(38.3)	$24.9	$26.3

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Selected Performance Metrics:

	For the Three Months Ended			
	December 31, 2012	September 30, 2012	June 30, 2012	March 31, 2012
Average net daily production equivalent (MMCFE per day)	659.6	619.6	555.7	557.0
Lease operating expense (per MCFE)	$0.79	$0.82	$0.91	$0.78
Transportation costs (per MCFE)	$0.71	$0.65	$0.60	$0.56
Production taxes as a percent of oil, gas, and NGL production revenue	4.8 %	5.1 %	4.7 %	5.3 %
Depletion, depreciation and amortization and asset retirement obligation liability accretion (per MCFE)	$3.37	$3.38	$3.20	$3.35
General and administrative (per MCFE)	$0.47	$0.56	$0.62	$0.56

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A year-to-year overview of selected production and financial information, including trends:

	As of and for the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2012	2011	2010	2012/2011	2011/2010	2012/2011	2011/2010
Net production volumes [1]							
Oil (MMBbl)	10.4	8.1	6.4	2.3	1.7	28 %	27 %
Gas (Bcf)	120.0	100.3	71.9	19.7	28.5	20 %	40 %
NGLs (MMBbl)	6.1	3.5	—	2.6	3.5	75 %	N/A
BCFE	218.9	169.7	110.0	49.2	59.7	29 %	54 %
Average net daily production [1]							
Oil (MBbl per day)	28.3	22.1	17.4	6.2	4.7	28 %	27 %
Gas (MMcf per day)	328.0	274.8	196.9	53.1	78.0	19 %	40 %
NGLs (MBbl per day)	16.7	9.6	—	7.1	9.6	75 %	N/A
Equivalent (MMCFE per day)	598.2	465.0	301.4	133.2	163.6	29 %	54 %
Oil, gas, and NGL production revenues (in millions)							
Oil production revenue	$886.2	$712.8	$461.9	$173.4	$250.9	24 %	54 %
Gas production revenue	$357.7	$433.4	$374.4	$(75.7)	$59.0	(17)%	16 %
NGL production revenue	$230.0	$186.2	$—	$43.8	$186.2	24 %	N/A
Total	$1,473.9	$1,332.4	$836.3	$141.5	$496.1	11 %	59 %
Oil, gas, and NGL production expense (in millions)							
Lease operating expenses	$180.1	$149.8	$121.5	$30.3	$28.3	20 %	23 %
Transportation costs	$138.9	$86.4	$21.2	$52.5	$65.2	61 %	308 %
Production taxes	$72.9	$53.9	$52.4	$19.0	$1.5	35 %	3 %
Total	$391.9	$290.1	$195.1	$101.8	$95.0	35 %	49 %
Realized price							
Oil (per Bbl)	$85.45	$88.23	$72.65	$(2.78)	$15.58	(3)%	21 %
Gas (per Mcf)	$2.98	$4.32	$5.21	$(1.34)	$(0.89)	(31)%	(17)%
NGLs (per Bbl)	$37.61	$53.32	$—	$(15.71)	$53.32	(29)%	N/A
Per MCFE	$6.73	$7.85	$7.60	$(1.12)	$0.25	(14)%	3 %
Per MCFE data							
Production costs:							
Lease operating expense	$0.82	$0.88	$1.10	$(0.06)	$(0.22)	(7)%	(20)%
Transportation costs	$0.63	$0.51	$0.19	$0.12	$0.32	24 %	168 %
Production taxes	$0.33	$0.32	$0.48	$0.01	$(0.16)	3 %	(33)%
General and administrative	$0.55	$0.70	$0.97	$(0.15)	$(0.27)	(21)%	(28)%
Depletion, depreciation and amortization and asset retirement obligation liability accretion	$3.32	$3.01	$3.06	$0.31	$(0.05)	10 %	(2)%
Derivative cash settlement (gain) loss[2]	$(0.22)	$0.27	$(0.22)	$(0.49)	$0.49	(181)%	(223)%
Earnings per share information							
Basic net income (loss) per common share	$(0.83)	$3.38	$3.13	$(4.21)	$0.25	(125)%	8 %
	$(0.83)	$3.19	$3.04	$(4.02)	$0.15	(126)%	5 %

Diluted net income (loss) per common share											
Basic weighted-average common shares outstanding (in thousands)	65,138	63,755	62,969	1,383		786	2	%	1		%
Diluted weighted-average common shares outstanding (in thousands)	65,138	67,564	64,689	(2,426	)	2,875	(4	)%	4		%

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(1) Amount and percentage changes may not recalculate due to rounding.
(2) Derivative cash settlements are included within the realized hedge gain (loss) and unrealized and realized derivative (gain) loss line items in the accompanying statements of operations.

Note: 2010 NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes. Please refer to additional discussion under the caption Oil, Gas, and NGL Prices above.

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require analysis. Average daily production for the year ended December 31, 2012, increased 29 percent compared to the same period in 2011, driven by the development of our Eagle Ford shale program and a substantial increase in production from our Bakken/Three Forks program.

Changes in production volumes, revenues, and costs reflect the highly volatile nature of our industry. Our realized price on a per MCFE basis for the year ended December 31, 2012, decreased 14 percent compared with the same period in 2011. The decrease in realized price is due to an overall decline in commodity prices, most significantly gas and NGL prices, during 2012.

LOE on a per MCFE basis for the year ended December 31, 2012, decreased seven percent compared with the same period in 2011. Absolute dollars for LOE in all regions increased in 2012, however production increased at a faster rate thereby reducing LOE on a per MCFE basis. Additionally, the 2011 divestiture of certain of our non-strategic Mid-Continent region properties, which had meaningfully higher per unit operating costs, reduced our LOE on a per MCFE basis for the year ended December 31, 2012. LOE in our South Texas & Gulf Coast region decreased in the second half of 2012 due to cost saving initiatives in the region. Based upon the current level of industry activity, we believe that LOE on a per MCFE basis will remain stable throughout 2013.

Transportation costs on a per MCFE basis for the year ended December 31, 2012, increased 24 percent compared to the same period in 2011. This is a result of increased production in our Eagle Ford shale program, where our transportation arrangements have higher per unit costs compared with our other regions. We anticipate transportation costs will continue to increase on a per MCFE basis as our Eagle Ford shale program becomes a larger portion of our total production.

Production taxes on a per MCFE basis for the year ended December 31, 2012, increased three percent compared with the same period in 2011. In the second quarter of 2011, we were notified that we qualified for severance tax incentive rebate programs for wells meeting specific criteria in certain areas of Texas. A sizable incentive tax rebate was recorded in the second quarter of 2011, significantly decreasing the per MCFE rate for the year ended December 31, 2011. We expect our future operated wells drilled in these areas to qualify for incentive tax rebate programs. We generally expect production taxes to trend with oil, gas, and NGL revenues.

General and administrative expense on a per MCFE basis for the year ended December 31, 2012, decreased 21 percent compared with the same period in 2011, as production increased at a faster rate than our general and administrative expense. A portion of our general and administrative expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. The Net Profits Plan and a portion of our short-term incentive compensation program correlate with net cash flows and therefore are subject to variability.

DD&A expense, for the year ended December 31, 2012, increased 10 percent, on a per MCFE basis, compared with the same period in 2011. Our DD&A rate increased as a result of the transfer of a portion of our non-operated working interest to Mitsui, which reduced our reserve base but had no impact on the carrying value of our assets. As we utilize our carry with Mitsui, we expect our DD&A rate to improve as we add reserves without incurring capital costs. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement in Part II, Item 8 of this report for additional discussion on the Mitsui transaction. Our DD&A rate can

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fluctuate as a result of impairments, divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Additionally, the accounting treatment for assets that are classified as held for sale can also impact our DD&A rate since these properties are no longer depleted.

Please refer to Comparison of Financial Results and Trends between 2012 and 2011 for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.

Please refer to the section Earnings per Share in Note 1 - Summary of Significant Accounting Policies in Part II, Item 8 of this report for additional discussion on the types of shares included in our basic and diluted net income (loss) per common share calculations. During the second quarter of 2012, all of our outstanding 3.50% Senior Convertible Notes were redeemed or net share settled following conversion. The shares issued upon conversion are reflected in our basic weighted-average common shares outstanding calculations for the year ended December 31, 2012. We recorded a net loss for the year ended December 31, 2012. Consequently, our in-the-money stock options, unvested RSUs, and contingent PSUs were anti-dilutive for the year resulting in a decrease in the diluted weighted-average common shares outstanding when compared with the year ended December 31, 2011. Please refer to Note 5 - Long-term Debt in Part II, Item 8 of this report for additional discussion on our 3.50% Senior Convertible Notes.

Comparison of Financial Results and Trends between 2012 and 2011

Oil, gas, and NGL production revenue. The following table presents the regional changes in our production and oil, gas, and NGL revenues and costs between the years ended December 31, 2012, and 2011:

	Average Net Daily Production Added (Lost)	Oil, Gas & NGL Revenue Added (Lost)	Production Costs Increase
	(MMCFE/d)	(in millions)	(in millions)
South Texas & Gulf Coast	116.8	$137.0	$68.9
Rocky Mountain	27.7	113.1	26.1
Mid-Continent	(10.6)	(92.1)	2.3
Permian	(0.7)	(16.5)	4.5
Total	133.2	$141.5	$101.8

The largest regional production increase occurred in the South Texas & Gulf Coast region as a result of drilling activity in our Eagle Ford shale program. Production in our Eagle Ford shale program continues to increase and we expect it to do so for the next several years. We also saw an increase in production in our Rocky Mountain region as a result of strong production performance from wells drilled in our Bakken/Three Forks program in late 2011 and throughout 2012.

The following table summarizes the realized prices we received in 2012 and 2011, before the effects of derivative cash settlements:

	For the Years Ended December 31,	
	2012	2011
Realized oil price ($/Bbl)	$85.45	$88.23
Realized gas price ($/Mcf)	$2.98	$4.32
Realized NGL price ($/Bbl)	$37.61	$53.32
Realized equivalent price ($/MCFE)	$6.73	$7.85

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A 29 percent increase in production on an equivalent basis combined with a 14 percent decrease in realized price per MCFE resulted in an 11 percent increase in revenue between the two periods. Based on current levels of activity, we expect production volumes to increase annually for the next several years. We also expect our realized prices to trend with commodity prices.

Realized hedge gain (loss). We recorded a net realized hedge gain of $3.9 million for the year ended December 31, 2012, compared with a net realized hedge loss of $20.7 million for the same period in 2011. These amounts are comprised of realized cash settlements on commodity derivative contracts that were designated as cash flow hedges and were previously recorded in accumulated other comprehensive income (loss) ("AOCIL"). Our realized oil, gas, and NGL hedge gains and losses are a function of commodity prices at the time of settlement compared with the respective derivative contract prices.

Gain (loss) on divestiture activity. We recorded a net loss on divestiture activity of $27.0 million for the year ended December 31, 2012, compared with a net gain of $220.7 million for the comparable period of 2011. The net loss on divestiture activity for the year ended December 31, 2012, is due to a loss on unsuccessful property sale efforts and the write-down of certain assets held for sale to their fair value. This loss was offset partially by a net gain on completed divestitures. The net gain for the year ended December 31, 2011, relates to the divestitures of oil and gas properties located in our South Texas & Gulf Coast, Rocky Mountain, and Mid-Continent regions. We will continue to evaluate our portfolio to determine whether there are non-strategic properties we could divest. Please refer to Divestiture Activity and Unsuccessful Sale of Properties above and Note 3 - Assets Held for Sale in Part II, Item 8 of this report for additional discussion.

Marketed gas system revenue and expense. Marketed gas system revenue decreased to $52.8 million for the year ended December 31, 2012, compared with $69.9 million for the comparable period of 2011, as a result of lower production in the Mid-Continent region and declining gas prices. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased to $47.6 million for the year ended December 31, 2012, from $64.2 million for the comparable period of 2011. There was no significant change in our net margin. We expect that marketed gas system revenue and expense will continue to correlate with increases and decreases in production and our realized gas price.

Oil, gas, and NGL production expense. Total production costs increased $101.8 million, or 35 percent, to $391.9 million for the year ended December 31, 2012, compared with $290.1 million in 2011, primarily due to a 29 percent increase in net production volumes on an equivalent basis. Please refer to our caption A year-to-year overview of selected production and financial information, including trends above for discussion of production costs on a per MCFE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased 42 percent to $727.9 million in 2012 compared with $511.1 million in 2011 due to an increase in our depreciable asset base as a result of continued development of our Eagle Ford and Bakken/Three Forks assets and the associated growth of our production. Please refer to our caption A year-to-year overview of selected production and financial information, including trends above for discussion of DD&A expense on a per MCFE basis.

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Exploration. The components of exploration expense are summarized as follows:

	For the Years Ended December 31,	
	2012	2011
Summary of Exploration Expense	(in millions)	
Geological and geophysical expenses	$13.6	$7.3
Exploratory dry hole	20.9	0.3
Overhead and other expenses	55.7	45.9
Total	$90.2	$53.5

Exploration expense for 2012 increased 69 percent compared with the same period in 2011 as a result of wells categorized as exploratory being classified as dry during the year, as well as an increase in exploration overhead and geological and geophysical expenses ("G&G") due to an increase in our exploration efforts. An exploratory project resulting in non-commercial quantities of oil, gas, or NGLs is deemed an exploratory dry hole and impacts the amount of exploration expense we record.

Impairment of proved properties. We recorded impairment of proved properties expense of $208.9 million for the year ended December 31, 2012. The impairments were a result of write-downs of our Wolfberry assets in our Permian region due to downward engineering revisions, as well as write-downs of our Haynesville shale assets due to low natural gas prices. We recorded impairment of proved properties expense of $219.0 million for the comparable period in 2011 related to legacy assets located in our Mid-Continent region as a result of depressed natural gas prices.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $16.3 million for the year ended December 31, 2012, the majority of which related to acreage we no longer intend to develop in our Rocky Mountain and Mid-Continent regions. We recorded $7.4 million of abandonment and impairment of unproved properties expense for the comparable period in 2011, primarily associated with lease expirations in our Mid-Continent region. We expect abandonment and impairment of unproved properties to more likely occur in periods of low commodity prices, which negatively impact operating cash flows available for exploration and development, as well as anticipated economic performance.

General and administrative. General and administrative expense increased slightly to $119.8 million for the year ended December 31, 2012, compared with $118.5 million for the same period in 2011. The change is due to an increase in employee headcount in 2012, which resulted in an increase to base compensation, benefits, and general corporate office expenses incurred. These were mostly offset by an increase in COPAS overhead reimbursement as a result of an increase in operated well count, as well as an overall decrease in accruals for cash bonus that reflect less success at reaching performance metrics when compared with the prior year. Please refer to our caption A year-to-year overview of selected production and financial information, including trends above for discussion of general and administrative costs on a per MCFE basis.

Change in Net Profits Plan liability. This non-cash expense generally relates to the change in the estimated value of the associated liability between the reporting periods. For 2012, we recorded a non-cash benefit of $28.9 million compared to a non-cash benefit of $25.5 million in 2011. The change in our liability is subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, and production costs. Payments made to participants as a result of divestitures and ongoing operations will also impact our liability. Please refer to Note 11 - Fair Value Measurements in Part II, Item 8 of this report for the impact a direct payment made to cash-out several pools had on our change in Net Profits Plan liability in 2011.

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Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative gain of $55.6 million in 2012 compared to a gain of $37.1 million for the same period in 2011. Declining commodity prices in both periods resulted in favorable derivative positions and settlements. These amounts include the change in fair value of commodity derivative contracts and realized cash settlement gains or losses on derivatives for which unrealized changes in fair value were not previously recorded in AOCIL. Please refer to Note 10 - Derivative Financial Instruments in Part II, Item 8 of this report for additional discussion.

Other operating expense. Other operating expense was $7.0 million in 2012 compared with $17.6 million in 2011. The decrease is a result of commissions and legal costs incurred in 2011 associated with our Acquisition and Development Agreement with Mitsui, as well as legal costs incurred related to the arbitration proceedings involving Anadarko E&P Company, LP during the second half of 2011. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement, in Part II, Item 8 of this report for additional discussion of our Acquisition and Development Agreement.

Income tax benefit (expense). We recorded an income tax benefit of $29.3 million for 2012 compared to an expense of $123.6 million for 2011, resulting in effective tax rates of 35.0 percent and 36.5 percent, respectively. The net decrease in the rate reflects differing effects between years of the individual components of our tax rate. Comparable valuation allowance amounts recorded on state net operating losses and charitable contributions in each of the two years had the effect of increasing the 2011 rate of expense while decreasing the 2012 benefit rate. The impacts from these two items were mostly offset by the effect from recognized research and development credit benefits. Other 2012 net decreases in the effective rate resulted from changes in the mix of the highest marginal state tax rates, the differing effects from percentage depletion and other permanent differences. The current income tax expense in 2012 was $370,000 compared with the income tax benefit of $204,000 in 2011 which included a federal carryback amount.

In January 2013 federal legislation was passed extending the R&D credit to our 2012 and 2013 tax years. Since the legislation was not passed as of December 31, 2012, our 2012 income tax benefit does not reflect an impact for 2012 credit amounts. As of the filing date of this report we have not prepared a study for 2012 while we await the outcome of an on-going audit for R&D credits claimed for our 2007 through 2010 tax years. We are uncertain of when we may complete a study or the impact calculated 2012 and 2013 R&D tax credits would have on our income tax expense and tax rates for 2013. Even with a R&D credit, we expect our tax rate to be higher in 2013.

Comparison of Financial Results between 2011 and 2010

Oil, gas and NGL production revenue. Average daily production for the year ended December 31, 2011, increased 54 percent to 465.0 MMCFE, compared with 301.4 MMCFE for the same period in 2010. The following table presents the regional changes in our production and oil, gas, and NGL revenues and costs between the two years. Effective January 1, 2012, we combined our ArkLaTex region into our Mid-Continent region, based in Tulsa, Oklahoma, for operational and reporting purposes. Prior period presentation has been conformed to reflect this change.

	Average Net Daily Production Added (Lost) (MMCFE/d)	Oil and Gas Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	129.0	$348.9	$79.0
Rocky Mountain	4.9	96.1	12.2
Mid-Continent	38.4	63.3	4.1
Permian	(8.7)	(12.2)	(0.3)
Total	163.6	$496.1	$95.0

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The largest regional production increase occurred in the South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program. We also saw an increase in production in our Mid-Continent region as a result of strong production performance from wells drilled in our Haynesville shale program in late 2010 and early 2011.

The following table summarizes the average realized prices we received in 2011 and 2010, before the effects of derivative cash settlements:

	For the Years Ended December 31,	
	2011	2010
Realized oil price ($/Bbl)	$88.23	$72.65
Realized gas price ($/Mcf)	$4.32	$5.21
Realized NGL price ($/Bbl)	$53.32	$—
Realized equivalent price ($/MCFE)	$7.85	$7.60

Note: Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to separately show natural gas and NGL production volumes, revenues, and pricing consistent with title transfer for each product.

The three percent increase in average realized prices per MCFE coupled with a 54 percent increase in production volumes between periods resulted in a meaningful increase in revenue.

Realized hedge gain (loss). We recorded a net realized hedge loss of $20.7 million for the year ended December 31, 2011, compared with a net realized hedge gain of $23.5 million for the same period in 2010. The realized net loss in 2011 is comprised of realized cash settlements on commodity contracts that were previously recorded in AOCL, whereas the realized net gain in 2010 is comprised of realized cash settlements on all commodity derivative contracts.

Gain (loss) on divestiture activity. We recorded a gain on divestiture activity of $220.7 million, which was net of the $27.5 million write-down related to our Marcellus shale assets, for the year ended December 31, 2011, compared with a gain of $155.3 million for the comparable period of 2010. The 2011 gain related to the divestitures of oil and gas properties located in our South Texas & Gulf Coast, Rocky Mountain, and Mid-Continent regions. The 2010 gain related to the divestitures of oil and gas properties located in our Rocky Mountain and Permian regions.

Marketed gas system revenue and expense. Marketed gas system revenue was $69.9 million for the year ended December 31, 2011, which was relatively flat compared to $70.1 million for the year ended December 31, 2010. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased to $64.2 million for the year ended December 31, 2011, from $66.7 million for the comparable period of 2010.

Oil and gas production expense. Total production costs increased $95.0 million, or 49 percent, to $290.1 million for the year ended December 31, 2011, compared with $195.1 million in 2010 due primarily to a 54 percent increase in equivalent production volumes in 2011. Total oil, gas, and NGL production costs per MCFE decreased $0.06 to $1.71 for the year ended December 31, 2011, compared with $1.77 in 2010, due to a decrease in recurring LOE resulting from the sale of non-strategic properties with higher per unit LOE costs, as well as a decrease in production taxes per MCFE due to severance tax incentives in our South Texas & Gulf Coast and Mid-Continent regions. These decreases were offset slightly by an increase in transportation costs per MCFE, which was primarily a result of increased production in our Eagle Ford shale program where our transportation agreements have higher per unit transportation costs due to the lack of infrastructure in the emerging play.

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Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased 52 percent to $511.1 million for the year ended December 31, 2011, compared with $336.1 million in 2010. The increase in overall DD&A expense was due to increased production. DD&A expense per MCFE decreased two percent to $3.01 for the year ended December 31, 2011, compared to $3.06 in 2010 due to an increase in our reserve base and production volumes, while our property balances remained relatively constant between the two periods.

Exploration. The components of exploration expense are summarized as follows:

	For the Years Ended December 31,	
	2011	2010
Summary of Exploration Expense	(in millions)	
Geological and geophysical expenses	$7.3	$21.5
Exploratory dry hole	0.3	0.3
Overhead and other expenses	45.9	42.1
Total	$53.5	$63.9

Exploration expense in 2011 decreased 16 percent compared to the same period in 2010 due to a reduction in geological and geophysical expense, as a result of a decrease in our exploration efforts in 2011. The increase in exploration overhead costs related to equity incentive compensation expense as discussed under General and administrative below.

Impairment of proved properties. We recorded $219.0 million of impairment of proved properties expense in 2011, compared to $6.1 million in 2010. The impairment in 2011 related to assets located in our Mid-Continent region that were impacted by significantly lower natural gas prices in the second half of 2011.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $7.4 million for the year ended December 31, 2011, associated with lease expirations in our Mid-Continent region. We recorded $2.0 million of abandonment and impairment of unproved properties expense for the comparable period in 2010, associated with lease expirations in our Rocky Mountain and Mid-Continent regions.

General and administrative. General and administrative expense increased 11 percent to $118.5 million for the year ended December 31, 2011, compared with $106.7 million for the same period in 2010. The change was due to an increase in base and equity incentive compensation and accruals for cash bonuses, as well as an increase in corporate office expenses as a result of an increase in employee headcount between the two periods. General and administrative expense per MCFE decreased $0.27 to $0.70 per MCFE for the year ended December 31, 2011, compared to $0.97 in 2010, mostly due to our production increasing at a faster rate than our general and administrative expense.

Change in Net Profits Plan liability. For 2011, the change in the Net Profits Plan liability, a non-cash item, was a $25.5 million benefit compared to a $34.4 million benefit in 2010. This non-cash charge or benefit is directly related to the change in the estimated value of the associated liability between the reporting periods. Please refer to Note 11 - Fair Value Measurements in Part II, Item 8 of this report for the impact a direct payment made to cash-out several pools had on our change in Net Profits Plan liability in 2011.

Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative gain of $37.1 million in 2011 compared to a loss of $8.9 million for the same period in 2010. The 2011 amount includes gains resulting from unrealized changes in fair value on commodity derivative contracts of $62.8 million and realized cash settlement losses on derivatives for which unrealized changes in fair value were not previously recorded in other comprehensive loss of $25.7 million. The 2010 activity is comprised solely of the ineffective portion of derivatives designated as cash flow hedges.

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Other operating expense. Other operating expense was $17.6 million in 2011 compared with $3.0 million in 2010. The increase was a result of commission and legal costs associated with our Acquisition and Development Agreement with Mitsui, as well as legal costs related to the arbitration proceedings against Anadarko E&P Company, LP during the second half of 2011.

Income tax benefit (expense). Income tax expense totaled $123.6 million for 2011 compared to tax expense of $118.1 million for 2010, resulting in effective tax rates of 36.5 percent and 37.5 percent, respectively. The effective rate change from 2010 primarily reflected changes in the mix of the highest marginal state tax rates, a multi-year research and experimentation credit claim, an adjustment for anticipated utilization of charitable contributions carryovers, and differing effects of other permanent differences including percentage depletion. The current income tax benefit in 2011 was $204,000 compared with current income tax expense of $3.5 million in 2010. These amounts were three percent of the total income tax expense for 2010 and were not material for 2011.

Overview of Liquidity and Capital Resources

We believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion services commitments in order to provide us with some flexibility to reduce activity and capital expenditures in periods of prolonged commodity price decline.

Sources of cash

We currently expect our 2013 capital program to be partially funded by cash flows from operations, with an anticipated shortfall to be funded by borrowings under our credit facility. Although we anticipate that cash flow from operations and borrowing capacity under our credit facility will be sufficient to fund our expected 2013 capital program, we may also elect to access the capital markets, depending on prevailing market conditions. The divestiture of certain oil and gas properties is also a potential source of funding and we will continue to evaluate our portfolio to identify potential divestiture candidates.

Our primary sources of liquidity are the cash flows provided by our operating activities, borrowings under our credit facility, proceeds received from divestitures of properties, and other financing alternatives, including accessing capital markets. From time to time, we may enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. All of our sources of liquidity can be impacted by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, gas, or NGLs, although we are able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of producing properties, or newly issued debt. See “Credit Facility” below for a discussion of our most recent borrowing base redetermination. Historically, decreases in commodity prices have limited our industry’s access to capital markets.

In the second quarter of 2012, we issued $400.0 million in aggregate principal amount of 6.50% Senior Notes due 2023. Additionally, some of the proceeds from our 2021 Notes issued in the fourth quarter of 2011 were available for use in 2012. In late 2011, we consummated our Acquisition and Development Agreement with Mitsui pursuant to which Mitsui funds, or carries, 90 percent of certain drilling and completion costs attributable to our remaining interest in our non-operated Eagle Ford shale acreage until $680.0 million has been expended on our behalf. Of the original $680.0 million carry amount, $277.5 million had been spent as of December 31, 2012. The remaining carry is expected to be realized over approximately the next two years. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement in Part II, Item 8 of this report for additional discussion.

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Proposals to fund the federal government budget continue to include eliminating or reducing current tax deductions for intangible drilling costs, the domestic production activities deduction, and percentage depletion. Legislation modifying or eliminating these deductions would have the immediate effect of reducing operating cash flows thereby reducing funding available for our exploration and development capital programs and those of our peers in the industry. If enacted, these funding reductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit facility

In May 2011, we entered into our Fourth Amended and Restated Credit Agreement, providing a $2.5 billion senior secured revolving credit facility with a scheduled maturity date of May 27, 2016. In the third quarter of 2012, our borrowing base under the credit facility was increased to $1.55 billion from $1.4 billion. Our borrowing base is subject to regular semi-annual redeterminations by our lenders and the next scheduled re-determination date is April 1, 2013. As of the filing date of this report, our lenders have committed to a current aggregate commitment amount of $1.0 billion under the credit agreement. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. Through the filing date of this report, we have experienced no issues utilizing our credit facility. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility.

The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of February 14, 2013, December 31, 2012, and December 31, 2011.

	As of February 14, 2013	As of December 31, 2012	As of December 31, 2011
	(in millions)		
Credit facility balance	$407.5	$340.0	$—
Letters of credit [1]	$0.8	$0.8	$0.6
Available borrowing capacity	$591.7	$659.2	$999.4

[1] Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis.

Our daily weighted-average credit facility debt balance was approximately $171.8 million and $10.7 million for the years ended December 31, 2012, and 2011, respectively. Borrowings under our credit facility are secured by mortgages on substantially all of our proved oil and gas properties.

Weighted-average interest rates

Our weighted-average interest rates in the current and prior year include accrued interest payments, cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, amortization of the debt discount related to our 3.50% Senior Convertible Notes through April 2, 2012, and amortization of deferred financing costs. Our weighted-average borrowing rate is calculated using only our accrued interest and fee payments.
The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the years ended December 31, 2012, 2011, and 2010.

	For the Years Ended December 31,					
	2012		2011		2010	
Weighted-average interest rate	6.4	%	8.5	%	8.3	%
Weighted-average borrowing rate	5.5	%	5.2	%	2.8	%

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The decrease in our weighted-average interest rate from 2011 is a result of our Senior Notes being outstanding for all or a part of the year ended December 31, 2012, with rates below the 2011 average interest rate, as well as a higher average balance on our revolving credit facility, which provides a lower interest rate than all our fixed debt instruments and which reduces the fee paid on the unused portion of our aggregate commitment.

Our weighted-average borrowing rate for the year ended December 31, 2012, was impacted by the three tranches of high yield unsecured debt we have issued since February 2011, as well as the redemption and settlement of our 3.50% Senior Convertible Notes that occurred in the second quarter of 2012. Each tranche of high yield unsecured debt has a coupon rate that is higher than the coupon rate on the 3.50% Senior Convertible Notes, and is also higher than the average borrowing rate on the credit facility incurred during 2011. This had the effect of increasing our average borrowing rate since high yield unsecured debt replaced lower cost secured bank debt and our 3.50% Senior Convertible Notes.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to EBITDAX, as defined under the caption Non-GAAP Financial Measures below, of less than 4.0 to 1.0 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. As of December 31, 2012, our debt to EBITDAX ratio and adjusted current ratio, as defined by our credit agreement, were 1.40 and 1.81, respectively. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and general and administrative costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. During 2012, we spent $1.5 billion for exploration and development capital expenditures, and leasehold acquisition. These amounts differ from the cost incurred amounts, which are accrual-based and include asset retirement obligation, G&G, and exploration overhead amounts.

The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of available acquisition and drilling opportunities, our cash flow from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our operated and non-operated development and exploratory activities may lead to changes in funding requirements for future development. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, potential acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

As of the filing date of this report, subject to the approval of our Board of Directors, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility and the indentures governing our Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors reviews this program as part of the allocation of our capital. During 2012, we did not repurchase any shares of our common stock, and we currently do not plan to repurchase any outstanding shares.

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During 2012, we paid $6.5 million in dividends to our stockholders, which constitutes a dividend of $0.10 per share. Our intention is to continue to make dividend payments for the foreseeable future, subject to our future earnings, our financial condition, credit facility and other covenants, and other factors which could arise. Payment of future dividends remains at the discretion of our Board of Directors. Additionally, during the second quarter of 2012 we paid $287.5 million to settle our 3.50% Senior Convertible Notes.

The following table presents changes in cash flows between the years ended December 31, 2012, 2011, and 2010, for our operating, investing, and financing activities. The analysis following the table should be read in conjunction with our statements of cash flows in Part II, Item 8 of this report.

	For the Years Ended December 31,			Amount of Changes Between		Percent of Change Between	
	2012	2011	2010	2012/2011	2011/2010	2012/2011	2011/2010
	(in millions)						
Net cash provided by operating activities	$922.0	$760.5	$497.1	$161.5	$263.4	21 %	53 %
Net cash (used in) investing activities	$(1,457.3)	$(1,264.9)	$(361.6)	$(192.4)	$(903.3)	15 %	250 %
Net cash provided by (used in) financing activities	$422.1	$618.5	$(141.1)	$(196.4)	$759.6	(32)%	(538)%

Analysis of cash flow changes between 2012 and 2011

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $256.5 million, or 21 percent, to $1.5 billion for the year ended December 31, 2012, compared with the same period in 2011. This increase was due to an increase in production volumes and favorable derivative settlements resulting from declining commodity prices throughout the year. Cash paid for lease operating expenses in 2012 increased $28.4 million compared with 2011 due to increased production and higher service costs caused by increased demand for those services. Cash paid for interest during 2012 increased $29.2 million compared with the same period in 2011 due to interest payments on our Senior Notes, as well as an increase in interest payments under our credit facility arising from an increase in our weighted-average borrowings for the year.

Investing activities. Capital expenditures in 2012 decreased $125.3 million, or eight percent, compared with the same period in 2011. This decrease was a result of being carried for substantially all of our drilling and completion costs in our outside operated Eagle Ford program. Net proceeds from the sale of oil and gas properties decreased $309.1 million between the two periods due to a decrease in divestiture activity in 2012.

Financing activities. During 2012, we paid $287.5 million to settle our 3.50% Senior Convertible Notes. We received $392.1 million of net proceeds from the issuance of our 2023 Notes in 2012, compared with $684.2 million of proceeds from the issuance of our 2019 Notes and 2021 Notes in 2011. We had net borrowings under our credit facility of $340.0 million during 2012, compared with net repayments of $48.0 million made during 2011.

Analysis of cash flow changes between 2011 and 2010

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $409.4 million to $1.2 billion for the year ended December 31, 2011. The increase was due to an increase in production volumes. Cash paid for lease operating expenses in 2011 increased $26.5 million compared with 2010. We received $4.0 million in income tax refunds in 2011 compared to $25.6 million received during 2010.

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Investing activities. Cash used for investing activities was $1.3 billion for the year ended December 31, 2011, compared with $361.6 million for the same period in 2010. Cash spent on capital expenditures increased $964.8 million, or 144 percent, to $1.6 billion. This increase in capital and exploration activities was financed mainly by higher cash flows available from operating activities, divestiture proceeds, and proceeds from the issuance of our 2019 Notes and 2021 Notes. Proceeds received from divestitures increased $53.0 million to $364.5 million for the year ended December 31, 2011, due to an increase in the size of the divestiture packages.

Financing activities. Net repayments to our credit facility decreased $92.0 million for the year ended December 31, 2011, compared to 2010 as our strong cash position throughout 2011 resulted in decreased borrowings. After deducting aggregate fees of $15.8 million, we received aggregate net proceeds of $684.2 million due to the issuance of our 2019 Notes and 2021 Notes during 2011. We spent $8.7 million on debt issuance costs for our amended credit facility during the year ended December 31, 2011.

Interest Rate Risk

We are exposed to market risk due to the floating interest rate on our revolving credit facility. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months. To the extent that the interest rate is fixed, interest rate changes affect the credit facility's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes, but can impact fair market values. As of December 31, 2012, our fixed-rate debt outstanding totaled $1.1 billion. As of December 31, 2012, we had $340.0 million of floating-rate debt outstanding. The carrying amount of our floating-rate debt at December 31, 2012, approximates its fair value. Assuming a constant floating-rate debt level of $340.0 million, the before-tax cash flow impact resulting from a 100 basis point change in our interest rate would be $3.4 million over a 12-month time period.

Commodity Price Risk

The prices we receive for our oil, gas, and NGL production heavily impacts our revenue, overall profitability, access to capital and future rate of growth. Oil, gas, and NGLs are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, gas, and NGLs have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on our 2012 production, a 10 percent decrease in our average realized price received for oil, gas, and NGLs would have reduced our oil, gas, and NGL production revenues by $88.6 million, $35.8 million, and $23.0 million, respectively.

The fair values of our commodity derivative contracts are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2012, a 10 percent increase and 10 percent decrease in the forward curves associated with our commodity derivative instruments would have changed our net asset positions by the following amounts:

	10% Increase	10% Decrease
	(in thousands)	
Gain/(loss):		
Gas derivatives	$(66.9)	$61.9
Oil derivatives	$(29.0)	$29.0
NGL derivatives	$(5.4)	$5.4

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We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. Please refer to Note 10 – Derivative Financial Instruments of Part II, Item 8 of this report for additional information about our oil, gas, and NGL derivative contracts, and additional information below under the caption Summary of Oil, Gas, and NGL Derivative Contracts in Place.

Summary of Oil, Gas, and NGL Derivative Contracts in Place

Our oil, gas, and NGL derivative contracts include costless swaps and costless collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 10 – Derivative Financial Instruments in Part II, Item 8 of this report for additional information regarding accounting for our derivative transactions.

As of December 31, 2012, our commodity derivative contracts through the third quarter of 2015 totaled 10.1 million Bbls of oil, 80.7 million MMBtu of gas, and 1.2 million Bbls of NGLs. As of February 14, 2013, the Company had commodity derivative contracts in place through the fourth quarter of 2015 for a total of 14.5 million Bbls of oil, 114.8 million MMBtu of gas, and 2.0 million Bbls of NGLs.

In a typical commodity swap agreement, if the agreed-upon published third-party index price is lower than the swap fixed price, we receive the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. We pay the difference between the agreed upon contracted ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

The following tables summarize the approximate volumes, average contract prices, and fair value of contracts we had in place as of December 31, 2012:

Oil contracts

Oil Swaps:

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2012 (Liability)	
	(Bbls)	(per Bbl)	(in millions)	
First quarter 2013	514,000	$89.87	$(1.3	)
Second quarter 2013	534,000	$88.99	(2.4	)
Third quarter 2013	300,000	$91.47	(0.7	)
Fourth quarter 2013	265,000	$91.22	(0.5	)
2014	1,256,000	$90.92	(1.7	)
2015	355,000	$88.40	(0.7	)
All oil swaps	3,224,000		$(7.3	)

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Oil Collars:

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2012 Asset (Liability)
	(Bbls)	(per Bbl)	(per Bbl)	(in millions)
First quarter 2013	755,000	$79.87	$107.36	$0.1
Second quarter 2013	620,000	$76.65	$109.08	0.2
Third quarter 2013	765,000	$74.89	$107.98	(0.3)
Fourth quarter 2013	727,000	$81.02	$116.09	1.8
2014	2,174,000	$83.71	$107.93	5.2
2015	1,814,000	$85.00	$95.51	(0.1)
All oil collars	6,855,000			$6.9

Natural Gas Contracts
Natural Gas Swaps:

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2012 Asset (Liability)
	(MMBtu)	(per MMBtu)	(in millions)
First quarter 2013	8,611,000	$4.34	$9.2
Second quarter 2013	7,205,000	$3.99	4.5
Third quarter 2013	6,114,000	$4.19	4.2
Fourth quarter 2013	5,593,000	$4.38	3.9
2014	23,309,000	$4.14	4.4
2015	17,469,000	$4.02	(1.2)
All natural gas swaps*	68,301,000		$25.0

*Natural gas swaps are comprised of IF El Paso Permian (2%), IF HSC (56%), IF NGPL TXOK (4%), IF PEPL (16%), IF Reliant N/S (17%), and IF TETCO STX (5%).

Natural Gas Collars:

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2012 Asset
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in millions)
First quarter 2013	1,330,000	$4.39	$5.46	$1.5
Second quarter 2013	1,910,000	$4.39	$5.32	2.0
Third quarter 2013	1,770,000	$4.39	$5.31	1.7
Fourth quarter 2013	1,640,000	$4.39	$5.31	1.4
2014	5,734,000	$4.38	$5.36	4.0
All natural gas collars*	12,384,000			$10.6

*Natural gas collars are comprised of IF HSC (18%), IF NGPL TXOK (18%), IF Reliant N/S (29%), and IF TETCO STX (35%).

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NGL Contracts
NGL Swaps:

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2012 Asset
	(Bbls)	(per Bbl)	(in millions)
First quarter 2013	436,000	$46.21	$1.3
Second quarter 2013	371,000	$42.74	1.3
Third quarter 2013	222,000	$50.45	0.5
Fourth quarter 2013	206,000	$50.27	0.4
All NGL swaps*	1,235,000		$3.5

*NGL swaps are comprised of OPIS Mont. Belvieu Purity Ethane (37%), OPIS Mont. Belvieu LDH Propane (25%), OPIS Mont. Belvieu NON-LDH Isobutane (2%), OPIS Mont. Belvieu NON-LDH Normal Butane (16%), and OPIS Mont. Belvieu NON-LDH Natural Gasoline (20%).

Commodity Derivative Contracts Entered into After December 31, 2012

The following tables summarize all commodity derivative contracts entered between January 1, 2013, and February 14, 2013:
Oil contracts
Oil Swaps:

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
First quarter 2013	220,000	$98.25
Second quarter 2013	559,000	$98.25
Third quarter 2013	458,000	$97.50
Fourth quarter 2013	392,000	$95.85
2014	344,000	$95.85
All oil swaps	1,973,000	

Oil Collars:

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
2014	847,000	$85.00	$99.10
2015	1,552,000	$85.00	$92.79
All oil collars	2,399,000		

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Natural Gas Contracts
Natural Gas Swaps:

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Third quarter 2013	3,542,000	$3.57
Fourth quarter 2013	2,925,000	$3.57
2014	13,208,000	$3.90
All natural gas swaps*	19,675,000	

*Natural gas swaps are comprised of IF El Paso Permian (4%), IF HSC (77%), IF NGPL TXOK (3%), IF NNG Ventura (6%), IF PEPL (10%).

Natural Gas Collars:

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)
2015	14,480,000	$3.96	$4.30
All natural gas collars*	14,480,000		

*Natural gas collars are comprised of IF El Paso Permian (4%), IF HSC (72%), IF NNG Ventura (7%), IF PEPL (10%), IF Reliant N/S (7%).

NGL Contracts
NGL Swaps:

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
First quarter 2013	60,000	$75.37
Second quarter 2013	181,000	$74.36
Third quarter 2013	153,000	$74.25
Fourth quarter 2013	136,000	$74.20
2014	208,000	$75.87
All NGL swaps*	738,000	

*NGL swaps are comprised of OPIS Mont. Belvieu NON-LDH Isobutane (38%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (34%), and OPIS Mont. Belvieu NON-LDH Normal Butane (28%).

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Schedule of Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2012, for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$1,440.0	$—	$—	$340.0	$1,100.0
Interest payments (2)	624.3	77.9	155.8	146.3	244.3
Delivery commitments (3)	858.7	53.2	170.7	193.0	441.8
Operating leases and contracts (3)	153.9	74.6	40.8	11.0	27.5
Derivative liability (4)	15.8	9.0	6.8	—	—
Net Profits Plan (5)	77.5	16.6	28.9	22.5	9.5
Asset retirement obligations (6)	120.5	35.8	7.1	4.7	72.9
Other (7)	23.2	2.3	20.5	0.1	0.3
Total	$3,313.9	$269.4	$430.6	$717.6	$1,896.3

(1) Long-term debt consists of our Senior Notes and the outstanding balance under our long-term revolving credit facility, and assumes no principal repayment until the due dates of the instruments. The actual payments under our revolving credit facility may vary significantly.

(2) Interest payments on our Senior Notes are estimated assuming no principal repayment until the due dates of the instruments. Interest payments on our credit facility have been estimated using a rate of 1.75 percent and assume no principal repayment until the May 27, 2016, due date.

(3) Please refer to Note 6 – Commitments and Contingencies in Part II, Item 8 of this report for additional discussion regarding our operating leases, contracts, and gathering, processing, and transportation through-put commitments.

(4) Amount shown represents only the liability portion of the marked-to-market value of our commodity derivatives based on future market prices at December 31, 2012, and excludes estimated oil, gas, and NGL commodity derivative receipts. This amount varies from the liability amounts presented on the accompanying balance sheets, as those amounts are presented at fair value, which considers time value, volatility, and the risk of non-performance for us and for our counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market risk and commodity price volatility. Please refer to Note 10 – Derivative Financial Instruments in Part II, Item 8 of this report for additional discussion regarding our derivative contracts.

(5) Amount shown represents undiscounted forecasted payments for the Net Profits Plan for the next six years. Payments are expected to gradually decrease for the years beyond what are shown in this table and are not included due to these payments being highly variable, as outlined below. The amount recorded on the accompanying balance sheets reflects all future Net Profits Plan payments and the impact of discounting, and therefore differs from the amounts disclosed in this table. The variability in the amount of payments will be a direct reflection of commodity prices, production rates, capital expenditures, and operating costs in future periods. Predicting the timing and amounts of payments associated with this liability is contingent upon estimates of appropriate discount factors, adjusting for risk and time value, and upon a number of factors we cannot control. Please refer to Note 7 – Compensation Plans and Note 11 - Fair Value Measurements in Part II, Item 8 of this report for additional discussion regarding our Net Profits Plan liability.

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(6) Amount shown represents estimated future discounted abandonment costs. These obligations are recorded as liabilities on our December 31, 2012, accompanying balance sheets. The ultimate settlement of these obligations is unknown and can be impacted by federal and state regulations, as well as economic factors and therefore the actual timing of abandonment costs may vary significantly. Please refer to Note 9 – Asset Retirement Obligations in Part II, Item 8 of this report for additional discussion regarding our asset retirement obligations.

(7) The majority of the amount shown represents the remaining funded portion of our estimated pension liability of $20.0 million, although we recognize that we cannot accurately determine the timing of future payments, as well as insignificant amounts related to uncertain tax positions and our cash settlement balancing payable. We are expected to make contributions to the Pension Plan in 2013 of $373,000. We made contributions of $5.4 million and $5.3 million in 2012 and 2011, respectively, toward our pension liability.

In addition to the amounts in the above table, we entered into a three-year capital project commencing in 2011 for the development of infrastructure in our non-operated Eagle Ford shale play. Pursuant to the terms of the agreement for the construction, ownership and operation of the assets, we are required to pay our portion of the costs. Based on current estimates, we do not expect costs to exceed approximately $67 million over the remaining term of the agreement.

Off-balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of December 31, 2012, we have not been involved in any unconsolidated special purpose entity transactions.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements in conformity with accounting principles generally accepted in the United States (“GAAP”) requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses as well as the disclosure of contingent assets and liabilities as of the date of our financial statements. We base our assumptions and estimates on historical experience and various other sources that we believe to be reasonable under the circumstances. Actual results may differ from the estimates we calculate due to changes in circumstances, global economics and politics, and general business conditions. A summary of our significant accounting policies is detailed in Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report. We have outlined below those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Oil and gas reserve quantities. Our estimated reserve quantities and future net cash flows are critical to the understanding of the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in our financial statements, including the calculations of depletion and impairment of proved oil and gas properties and the estimate of our Net Profits Plan liability. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10 percent discount rate to

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be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves, including using independent reserve engineering consultants. We expect that periodic reserve estimates will change in the future as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves at June 30 and December 31 of each year. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with GAAP for the impact of additions and dispositions. Changes in depletion or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period the reserve estimates change. Please refer to Supplemental Oil and Gas Information in Part II, Item 8 of this report.

The following table presents information about reserve changes from period to period due to items we do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Years Ended December 31,		
	2012 BCFE Change	2011 BCFE Change	2010 BCFE Change
Revisions resulting from price changes	(72.7)	(25.3)	42.6
Revisions resulting from performance [1]	(92.0)	36.8	(17.9)
Total	(164.7)	11.5	24.7

(1) Performance revisions include the removal of proved undeveloped reserves that are no longer in our development plan within five years. 2011 includes the impact of our conversion to three stream production reporting.

As previously noted, commodity prices are volatile, and estimates of reserves are inherently imprecise. Consequently, we expect to continue experiencing these types of changes. Please refer to additional reserves discussion under Overview of the Company.

The following table reflects the estimated BCFE change and percentage change to our total reported reserve volumes from the described hypothetical changes:

	For the Years Ended December 31,					
	2012		2011		2010	
	BCFE Change	Percentage Change	BCFE Change	Percentage Change	BCFE Change	Percentage Change
A 10% decrease in SEC pricing	(67.4)	(4)%	(22.2)	(2)%	(13.9)	(1)%
A 10% decrease in proved undeveloped reserves	(76.1)	(4)%	(41.5)	(3)%	(29.7)	(3)%

The table above solely reflects the impact of a 10 percent change in SEC pricing or decrease in proved undeveloped reserves and does not include additional impacts to our proved reserves that may result from our internal intent to drill hurdles. Additional reserve information can be found in the reserve table and discussion included in Items 1 and 2 of Part I of this report, and in Supplemental Oil and Gas Disclosures of Part II, Item 8 of this report.

Successful efforts method of accounting. GAAP provides for two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method. Both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities. A more detailed description is included in Note 1 - Summary of Significant Accounting Policies of Part II, Item 8 of this report.

Revenue recognition. Our revenue recognition policy is significant because revenue is a key component of our results of operations and our forward-looking statements contained in our analysis of liquidity and capital resources. We derive our revenue primarily from the sale of produced oil, gas, and NGLs. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month, we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, NYMEX and local spot market prices, and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A 10 percent change in our year end revenue accrual would have impacted net income before tax by approximately $16 million in 2012.

Change in Net Profits Plan Liability. We record the estimated liability of future payments for our Net Profits Plan. The estimated liability is calculated based on a number of assumptions, including estimates of proved reserves, estimated future capital, present value discount factors, pricing assumptions, and overall market conditions. Please refer to Note 11 - Fair Value Measurements in Part II, Item 8 of this report for additional discussion.

Asset retirement obligations. We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells projected into the future based on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates, and determine what credit-adjusted risk-free discount rate to use. The impact to the accompanying statements of operations from these estimates is reflected in our depreciation, depletion, and amortization calculations and occurs over the remaining life of our respective oil and gas properties. Please refer to Note 9 – Asset Retirement Obligations in Part II, Item 8 of this report for additional discussion.

Impairment of oil and gas properties. Our proved oil and gas properties are recorded at cost. We evaluate our proved properties for impairment when events or changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our oil and gas properties and compare these undiscounted cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, and discount rates.

Unproved oil and gas properties are assessed periodically for impairment on a lease-by-lease basis based on the remaining lease terms, drilling results, commodity price outlook, and future capital allocations. An impairment allowance is provided on unproven property when we determine that the property will not be developed or the carrying value will not be realized. Please refer to Impairment of Proved and Unproved Properties in Note 1 - Summary of Significant Accounting Policies in Part II, Item 8 of this report for impairment results.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil, gas and NGL price volatility. The accounting treatment for the change in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is designated as a cash flow hedge. Effective January 1, 2011, we elected to de-designate all of our commodity derivatives that had previously been designated as cash flow hedges as of December 31, 2010, and have elected to discontinue hedge accounting prospectively.

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Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in accumulated other comprehensive loss until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the statement of income because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative's fair value and any ineffective portion of the derivative instrument's change in fair value is recognized immediately in earnings. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Income taxes. We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we use and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement could have an impact on our results of operations. A one percent increase and decrease in our effective tax rate would have changed our calculated income tax benefit by approximately $832,000 and $839,000, respectively, for the year ended December 31, 2012.

Accounting Matters

Please refer to the section entitled Recently Issued Accounting Standards under Note 1 – Summary of Significant Accounting Policies for additional information on the recent adoption of new authoritative accounting guidance in Part II, Item 8 of this report.

Environmental

We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes, and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. For additional information about hydraulic fracturing and related environmental matters, see Risk Factors – Risks Related to Our Business – Proposed federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

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Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other ‘‘greenhouse gases’’ present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

In terms of opportunities, the regulation of greenhouse gas emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways. For example, although climate change legislation could reduce the overall demand for the oil and natural gas that we produce, the relative demand for natural gas may increase because the burning of natural gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources, such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, natural gas may become a more attractive transportation fuel. Approximately 55 and 59 percent of our production on an MCFE basis in 2012 and 2011, respectively, was natural gas. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and natural gas reservoirs, could also benefit us through the potential to obtain greenhouse gas emission allowances or offsets from or government incentives for the sequestration of carbon dioxide.

Non-GAAP Financial Measures

EBITDAX represents income (loss) before interest expense, interest income, income taxes, depreciation, depletion, amortization and accretion, exploration expense, property impairments, non-cash stock compensation expense, unrealized derivative gains and losses, change in the Net Profits Plan liability, and gains and losses on divestitures. EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time or whose timing and/or amount cannot be reasonably estimated. EBITDAX is a non-GAAP measure that is presented because we believe that it provides useful additional

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information to investors, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to a financial covenant under our credit facility based on our debt to EBITDAX ratio. In addition, EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by (used in) operating activities, profitability, or liquidity measures prepared under GAAP. Because EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the EBITDAX amounts presented may not be comparable to similar metrics of other companies. The following table provides reconciliations of our net income (loss) and net cash provided by operating activities to EBITDAX for the periods presented:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Net income (loss) (GAAP)	$(54,249)	$215,416	$196,837
Interest expense	63,720	45,849	24,196
Interest income	(220)	(466)	(321)
Income tax (benefit) expense	(29,268)	123,585	118,059
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	727,877	511,103	336,141
Exploration	81,809	46,776	56,184
Impairment of proved properties	208,923	219,037	6,127
Abandonment and impairment of unproved properties	16,342	7,367	1,986
Stock-based compensation expense	30,185	26,824	26,743
Unrealized derivative (gain) loss	(11,366)	(62,757)	8,899
Change in Net Profits Plan liability	(28,904)	(25,477)	(34,441)
(Gain) loss on divestiture activity	27,018	(220,676)	(155,277)
EBITDAX (Non-GAAP)	1,031,867	886,581	585,133
Interest expense	(63,720)	(45,849)	(24,196)
Interest income	220	466	321
Income tax benefit (expense)	29,268	(123,585)	(118,059)
Exploration	(81,809)	(46,776)	(56,184)
Exploratory dry hole expense	20,861	277	289
Amortization of debt discount and deferred financing costs	6,769	18,299	13,464
Deferred income taxes	(29,638)	123,789	114,517
Plugging and abandonment	(2,856)	(5,849)	(8,314)
Other	527	(6,027)	(3,993)
Changes in current assets and liabilities	10,480	(40,794)	(5,881)
Net cash provided by operating activities (GAAP)	$921,969	$760,532	$497,097

Note: Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations for the component of stock-based compensation expense recorded to exploration.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity Price Risk and Interest Rate Risk and Summary of Oil, Gas, and NGL Derivative Contracts in Place in Item 7 above and is incorporated herein by reference.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SM Energy Company and Subsidiaries
Denver, Colorado

We have audited the accompanying consolidated balance sheets of SM Energy Company and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of SM Energy Company and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 21, 2013, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 21, 2013

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share amounts)

	December 31, 2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$5,926	$119,194
Accounts receivable (note 2)	254,805	210,368
Refundable income taxes	3,364	5,581
Prepaid expenses and other	30,017	68,026
Derivative asset	37,873	55,813
Deferred income taxes	8,579	4,222
Total current assets	340,564	463,204
Property and equipment (successful efforts method), at cost:		
Land	1,845	1,548
Proved oil and gas properties	5,401,684	4,378,987
Less - accumulated depletion, depreciation, and amortization	(2,376,170)	(1,766,445)
Unproved oil and gas properties	175,287	120,966
Wells in progress	273,928	273,428
Materials inventory, at lower of cost or market	13,444	16,537
Oil and gas properties held for sale net of accumulated depletion, depreciation and amortization of $20,676 in 2012 and $10,714 in 2011	33,620	246
Other property and equipment, net of accumulated depreciation of $22,442 in 2012 and $23,985 in 2011	153,559	71,369
Total property and equipment, net	3,677,197	3,096,636
Other noncurrent assets:		
Derivative asset	16,466	31,062
Restricted cash	86,773	124,703
Other noncurrent assets	78,529	83,375
Total other noncurrent assets	181,768	239,140
Total Assets	$4,199,529	$3,798,980
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 2)	$525,627	$456,999
Derivative liability	8,999	42,806
Other current liabilities	6,920	6,000
Total current liabilities	541,546	505,805
Noncurrent liabilities:		
Long-term credit facility	340,000	—
3.50% Senior Convertible Notes, net of unamortized discount of $2,431 in 2011	—	285,069
6.625% Senior Notes due 2019	350,000	350,000
6.50% Senior Notes due 2021	350,000	350,000

6.50% Senior Notes due 2023	400,000	—
Asset retirement obligation	112,912	87,167
Asset retirement obligation associated with oil and gas properties held for sale	1,393	1,277
Net Profits Plan liability	78,827	107,731
Deferred income taxes	537,383	568,263
Derivative liability	6,645	12,875
Other noncurrent liabilities	66,357	67,853
Total noncurrent liabilities	2,243,517	1,830,235
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 66,245,816 shares in 2012 and 64,145,482 shares in 2011; outstanding, net of treasury shares: 66,195,235 shares in 2012 and 64,064,415 shares in 2011	662	641
Additional paid-in capital	233,642	216,966
Treasury stock, at cost: 50,581 shares in 2012 and 81,067 shares in 2011	(1,221)	(1,544)
Retained earnings	1,190,397	1,251,157
Accumulated other comprehensive loss	(9,014)	(4,280)
Total stockholders' equity	1,414,466	1,462,940
Total Liabilities and Stockholders' Equity	$4,199,529	$3,798,980

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	For the Years Ended December 31, 2012	2011	2010
Operating revenues and other income:			
Oil, gas, and NGL production revenue	$1,473,868	$1,332,392	$836,288
Realized hedge gain (loss)	3,866	(20,707)	23,465
Gain (loss) on divestiture activity	(27,018)	220,676	155,277
Marketed gas system revenue	52,808	69,898	70,110
Other operating revenue	1,578	1,059	7,694
Total operating revenues and other income	1,505,102	1,603,318	1,092,834
Operating expenses:			
Oil, gas, and NGL production expense	391,872	290,111	195,075
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	727,877	511,103	336,141
Exploration	90,248	53,537	63,860
Impairment of proved properties	208,923	219,037	6,127
Abandonment and impairment of unproved properties	16,342	7,367	1,986
General and administrative	119,815	118,526	106,663
Change in Net Profits Plan liability	(28,904)	(25,477)	(34,441)
Unrealized and realized derivative (gain) loss	(55,630)	(37,086)	8,899
Marketed gas system expense	47,583	64,249	66,726
Other operating expense	6,993	17,567	3,027
Total operating expenses	1,525,119	1,218,934	754,063
Income (loss) from operations	(20,017)	384,384	338,771
Nonoperating income (expense):			
Interest income	220	466	321
Interest expense	(63,720)	(45,849)	(24,196)
Income (loss) before income taxes	(83,517)	339,001	314,896
Income tax benefit (expense)	29,268	(123,585)	(118,059)
Net income (loss)	$(54,249)	$215,416	$196,837
Basic weighted-average common shares outstanding	65,138	63,755	62,969
Diluted weighted-average common shares outstanding	65,138	67,564	64,689
Basic net income (loss) per common share	$(0.83)	$3.38	$3.13
Diluted net income (loss) per common share	$(0.83)	$3.19	$3.04

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	For the Years Ended December 31,		
	2012	2011	2010
Net income (loss)	$(54,249)	$215,416	$196,837
Other comprehensive income (loss), net of tax:			
Change in derivative instrument fair value	—	—	16,811
Reclassification to earnings	(2,264)	12,997	6,641
Pension liability adjustment	(2,470)	(1,795)	(980)
Total other comprehensive income (loss), net of tax	(4,734)	11,202	22,472
Total comprehensive income (loss)	$(58,983)	$226,618	$219,309

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except share amounts)

	Common Stock		Additional Paid-in	Treasury Stock		Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Shares	Amount	Earnings	Loss	Equity
Balances, January 1, 2010	62,899,122	$629	$160,516	(126,893)	$(1,204)	$851,583	$ (37,954)	$973,570
Net income	—	—	—	—	—	196,837	—	196,837
Other comprehensive income	—	—	—	—	—	—	22,472	22,472
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,297)	—	(6,297)
Issuance of common stock under Employee Stock Purchase Plan	52,948	1	1,669	—	—	—	—	1,670
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings, including income tax cost of RSUs	113,103	1	(2,094)	—	—	—	—	(2,093)
Issuance of common stock upon stock option exercises, including income tax benefit	346,377	3	5,621	—	—	—	—	5,624
Stock-based compensation expense	1,250	—	25,962	24,258	781	—	—	26,743
Balances, December 31, 2010	63,412,800	$634	$191,674	(102,635)	$(423)	$1,042,123	$ (15,482)	$1,218,526
Net income	—	—	—	—	—	215,416	—	215,416
Other comprehensive income	—	—	—	—	—	—	11,202	11,202
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,382)	—	(6,382)
Issuance of common stock under Employee Stock Purchase Plan	41,358	—	2,300	—	—	—	—	2,300
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax	278,773	3	(9,976)	—	—	—	—	(9,973)

withholdings								
Issuance of common stock upon stock option exercises	412,551	4	5,023	—	—	—	—	5,027
Stock-based compensation expense	—	—	27,945	21,568	(1,121)	—	—	26,824
Balances, December 31, 2011	64,145,482	$641	$216,966	(81,067)	$(1,544)	$1,251,157	$ (4,280)	$1,462,940
Net loss	—	—	—	—	—	(54,249)	—	(54,249)
Other comprehensive loss	—	—	—	—	—	—	(4,734)	(4,734)
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,511)	—	(6,511)
Issuance of common stock under Employee Stock Purchase Plan	66,485	1	2,775	—	—	—	—	2,776
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	929,375	9	(21,631)	—	—	—	—	(21,622)
Issuance of common stock upon stock option exercises	240,368	2	3,038	—	—	—	—	3,040
Conversion of 3.50% Senior Convertible Notes to common stock, including income tax benefit of conversion	864,106	9	2,632	—	—	—	—	2,641
Stock-based compensation expense	—	—	29,862	30,486	323	—	—	30,185
Balances, December 31, 2012	66,245,816	$662	$233,642	(50,581)	$(1,221)	$1,190,397	$ (9,014)	$1,414,466

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Years Ended December 31, 2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$(54,249)	$215,416	$196,837
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
(Gain) loss on divestiture activity	27,018	(220,676)	(155,277)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	727,877	511,103	336,141
Exploratory dry hole expense	20,861	277	289
Impairment of proved properties	208,923	219,037	6,127
Abandonment and impairment of unproved properties	16,342	7,367	1,986
Stock-based compensation expense	30,185	26,824	26,743
Change in Net Profits Plan liability	(28,904)	(25,477)	(34,441)
Unrealized derivative (gain) loss	(11,366)	(62,757)	8,899
Amortization of debt discount and deferred financing costs	6,769	18,299	13,464
Deferred income taxes	(29,638)	123,789	114,517
Plugging and abandonment	(2,856)	(5,849)	(8,314)
Other	527	(6,027)	(3,993)
Changes in current assets and liabilities:			
Accounts receivable	(21,389)	(41,998)	(47,153)
Refundable income taxes	2,217	2,901	24,291
Prepaid expenses and other	(1,484)	16,376	(35,363)
Accounts payable and accrued expenses	31,136	(18,073)	53,198
Excess income tax benefit from the exercise of stock awards	—	—	(854)
Net cash provided by operating activities	921,969	760,532	497,097
Cash flows from investing activities:			
Net proceeds from sale of oil and gas properties	55,375	364,522	311,504
Capital expenditures	(1,507,828)	(1,633,093)	(668,288)
Acquisition of oil and gas properties	(5,773)	—	(664)
Other	893	3,661	(4,125)
Net cash used in investing activities	(1,457,333)	(1,264,910)	(361,573)
Cash flows from financing activities:			
Proceeds from credit facility	1,609,000	322,000	571,559
Repayment of credit facility	(1,269,000)	(370,000)	(711,559)
Debt issuance costs related to credit facility	—	(8,719)	—
Net proceeds from 6.625% Senior Notes due 2019	—	341,122	—
Net proceeds from 6.50% Senior Notes due 2021	—	343,120	—
Net proceeds from 6.50% Senior Notes due 2023	392,138	—	—
Repayment of 3.50% Senior Convertible Notes	(287,500)	—	—
Proceeds from sale of common stock	5,816	7,327	6,440
Dividends paid	(6,511)	(6,382)	(6,297)
Net share settlement from issuance of stock awards	(21,622)	(9,973)	(2,093)

Excess income tax benefit from the exercise of stock awards	—	—	854
Other	(225)	—	—
Net cash provided by (used in) financing activities	422,096	618,495	(141,096)
Net change in cash and cash equivalents	(113,268)	114,117	(5,572)
Cash and cash equivalents at beginning of period	119,194	5,077	10,649
Cash and cash equivalents at end of period	$5,926	$119,194	$5,077

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

Supplemental schedule of additional cash flow information and non-cash investing and financing activities:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Cash paid for interest, net of capitalized interest	$(51,328)	$(22,133)	$(13,340)
Net cash refunded for income taxes	$1,389	$4,046	$25,578

At December 31, 2012, 2011, and 2010, $262.8 million, $214.8 million, and $238.5 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

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SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Summary of Significant Accounting Policies
Description of Operations
SM Energy is an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America, with a current focus on oil and liquids-rich resource plays.

Basis of Presentation
The accompanying consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries and have been prepared in accordance with GAAP and the instructions to Form 10-K and regulation S-X. Subsidiaries that the Company does not control are accounted for using the equity or cost methods as appropriate. Equity method investments are included in other noncurrent assets in the accompanying consolidated balance sheets (“accompanying balance sheets”). Intercompany accounts and transactions have been eliminated. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2012, through the filing date of this report.
Use of Estimates in the Preparation of Financial Statements
The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of proved oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of proved oil and gas reserve quantities provide the basis for the calculation of depletion, depreciation, and amortization (“DD&A”), impairment of proved properties, asset retirement obligations, and the Net Profits Interest Bonus Plan (“Net Profits Plan”) liability, each of which represents a significant component of the accompanying consolidated financial statements.
Cash and Cash Equivalents
The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.
Restricted Cash
The Company’s restricted cash balance represents cash payments received from Mitsui that are contractually restricted to be used solely for development operations pursuant to the Company’s Acquisition and Development Agreement with Mitsui and accordingly are classified as non-current assets. Please refer to Note 12- Acquisition and Development Agreement and Carry and Earning Agreement for additional information.
Accounts Receivable
The Company’s accounts receivables consist mainly of receivables from oil, gas, and NGL purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, the Company’s oil and gas receivables are collected within two months, and the Company has had minimal bad debts.

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Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized. As of December 31, 2012, and 2011, the Company had no allowance for doubtful accounts recorded.

Concentration of Credit Risk and Major Customers

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is subject to continuous review. During 2012, we had two major customers, Regency Gas Services LLC and Plains Marketing LP, which accounted for approximately 21 percent and 13 percent, respectively, of our total production revenue. During 2011 and 2010, we had one major customer, Regency Gas Services LLC, individually account for approximately 18 percent and 11 percent, respectively, of our total production revenue.

The Company currently uses 10 separate counterparties for its oil, gas, and NGL commodity derivatives, all of which are participating lenders in the Company’s credit facility. Two of our counterparties were downgraded during 2012, but all maintain investment grade ratings. Nine counterparties carry corporate credit ratings at or exceeding A- and Baa2 by Standard & Poor’s and Moody’s, respectively. The remaining counterparty fell to BBB- and Baa2, respectively. In response, the Company requires cash collateral to be posted when its portfolio of trades with that counterparty is in an overall asset position.

The Company has accounts in the following locations with a national bank: Denver, Colorado; Shreveport, Louisiana; Houston, Texas; Midland, Texas; and Billings, Montana. The Company has accounts with a local bank in Tulsa, Oklahoma. The Company’s policy is to invest in highly-rated instruments and to limit the amount of credit exposure at each individual institution.

Oil and Gas Producing Activities

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. The application of the successful efforts method of accounting requires management’s judgment to determine the proper designation of wells as either development or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures within the accompanying consolidated statements of cash flows (“accompanying statements of cash flows”). The costs of development wells are capitalized whether those wells are successful or unsuccessful.

DD&A of capitalized costs related to proved oil and gas properties is calculated on a pool-by-pool basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. As of December 31, 2012, and 2011, the Company’s estimated salvage value was $64.4 million and $64.1 million, respectively.

Materials Inventory

The Company’s materials inventory is primarily comprised of tubular goods to be used in future drilling operations. Materials inventory is valued at the lower of cost or market and totaled $13.4 million and $16.5 million at December 31, 2012, and 2011, respectively. There were no materials inventory write-downs for the years ended December 31, 2012, 2011, or 2010.

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Assets Held for Sale

Any properties held for sale as of the balance sheet date have been classified as assets held for sale and are separately presented on the accompanying balance sheets at the lower of net book value or fair value less the cost to sell. The asset retirement obligation liabilities related to such properties have been reclassified to asset retirement obligations associated with oil and gas properties held for sale in the accompanying balance sheets. For additional discussion on assets held for sale, please refer to Note 3 – Divestitures and Assets Held for Sale.

Other Property and Equipment

Other property and equipment such as facilities, office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using either the straight-line method over the estimated useful lives of the assets, which range from three to thirty years, or the unit of output method where appropriate. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Intangible Assets

As of December 31, 2012, and 2011, the Company had $10.8 million and $7.1 million, respectively, of intangible assets consisting of acquired water rights, which are included as other noncurrent assets in the accompanying balance sheets. All indefinite lived intangible assets are evaluated for impairment if such indicators arise and at least annually.

Cash Settlement Balancing

The Company uses the sales method of accounting for gas revenue whereby sales revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company’s ownership in the property. An asset or liability is recognized to the extent that there is an imbalance in excess of the remaining gas reserves on the underlying properties. As of December 31, 2012, and 2011, the Company has recorded a receivable of $1.7 million and $1.9 million, respectively, and a liability of $1.3 million and $1.1 million, respectively, which is included as other noncurrent assets and other noncurrent liabilities in the accompanying balance sheets.

Derivative Financial Instruments

The Company seeks to manage or reduce commodity price risk on production by entering into derivative contracts. The Company seeks to minimize its basis risk and indexes its oil derivative contracts to NYMEX prices, its NGL derivative contracts to OPIS prices, and the majority of its gas derivative contracts to various regional index prices associated with pipelines in proximity to the Company’s areas of gas production. For additional discussion on derivatives, please see Note 10 – Derivative Financial Instruments.

Net Profits Plan

The Company records the estimated fair value of expected future payments made under the Net Profits Plan as a noncurrent liability in the accompanying balance sheets. The underlying assumptions used in the calculation of the estimated liability include estimates of production, proved reserves, recurring and workover lease operating expense, transportation, production and ad valorem tax rates, present value discount factors, pricing assumptions, and overall market conditions. The estimates used in calculating the long-term liability are adjusted from period-to-period based on the most current information attributable to the underlying assumptions. Changes in the estimated liability of future payments associated with the Net Profits Plan are recorded as increases or decreases to expense in the current period as a separate line item in the accompanying consolidated statements of operations (“accompanying statements of operations”), as these changes are considered changes in estimates.

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The distribution amounts due to participants and payable in each period under the Net Profits Plan as cash compensation related to periodic operations are recognized as compensation expense and are included within general and administrative expense and exploration expense in the accompanying statements of operations. The corresponding current liability is included in accounts payable and accrued expenses in the accompanying balance sheets. This treatment provides for a consistent matching of cash expense with net cash flows from the oil and gas properties in each respective pool of the Net Profits Plan. For additional discussion, please refer to the heading Net Profits Plan in Note 7 – Compensation Plans and Note 11 – Fair Value Measurements.

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. For additional discussion, please refer to Note 9 – Asset Retirement Obligations.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, gas, and NGLs. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported separately as expenses and are included in oil, gas, and NGL production expense in the accompanying statements of operations. Revenue is recorded in the month the Company's production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of its properties, their historical performance, NYMEX, OPIS, and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates.

Impairment of Proved and Unproved Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value, which is based on expected future discounted cash flows, when there is an indication that the carrying costs may not be recoverable. Expected future cash flows are calculated on all developed proved reserves and risk adjusted proved undeveloped, probable, and possible reserves using a discount rate and price forecasts selected by the Company's management. The discount rate is a rate that management believes is representative of current market conditions. The prices for oil and gas are forecasted based on NYMEX strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecasted using OPIS pricing, adjusted for basis differentials, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. An impairment is recorded on unproved property when the Company determines that either the property will not be developed or the carrying value is not realizable.

The Company recorded $208.9 million, $219.0 million, and $6.1 million, of proved property impairments for the years ended December 31, 2012, 2011, and 2010, respectively. The impairments in 2012 were a result of the Company's write-down of Wolfberry assets in its Permian region due to negative engineering revisions and the Company's Haynesville shale assets as a result of low natural gas prices. The impairments in 2011 were related to the Company's James Lime, Cotton Valley, and Haynesville shale assets as a result of significantly lower natural gas prices at the end of 2011.

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For the years ended December 31, 2012, 2011, and 2010, the Company recorded expense related to the abandonment and impairment of unproved properties of $16.3 million, $7.4 million, and $2.0 million, respectively. The Company's abandonment and impairment of unproved properties in 2012 related to acreage that the Company no longer intends to develop in the Rocky Mountain region.

Sales of Proved and Unproved Properties

The partial sale of proved properties within an existing field is accounted for as normal retirement and no gain or loss on divestiture activity is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an individual proved property is accounted for as a recovery of cost. A gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of proved properties.

The partial sale of unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to the ultimate recovery of the cost applicable to the interest retained. A gain on divestiture activity is recognized to the extent that the sales price exceeds the carrying amount of the unproved property. A gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of unproved property. For additional discussion, please refer to Note 3 – Divestitures and Assets Held for Sale.

Stock-Based Compensation

At December 31, 2012, the Company had stock-based employee compensation plans that included RSUs, PSUs, restricted stock awards, and stock options issued to employees and non-employee directors, as more fully described in Note 7 - Compensation Plans. The Company records expense associated with the fair value of stock-based compensation in accordance with authoritative accounting guidance, which is based on the estimated fair value of these awards determined at the time of grant.

Income Taxes

The Company accounts for deferred income taxes whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amounts on the financial statements and the tax basis of assets and liabilities, as measured using current enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recorded or settled, respectively. The Company records deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis.

Earnings per Share

Basic net income (loss) per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income or loss per common share is calculated by dividing adjusted net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options, unvested RSUs, contingent PSUs, and shares into which the 3.50% Senior Convertible Notes were convertible. When there is a loss from continuing operations, as was the case for the year ended December 31, 2012, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of earnings per share.

PSUs represent the right to receive, upon settlement of the PSUs after the completion of the three-year performance period, a number of shares of the Company's common stock that may range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that

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date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to Note 7 – Compensation Plans under the heading Performance Share Units Under the Equity Incentive Compensation Plan.

The Company called for redemption of its 3.50% Senior Convertible Notes on April 2, 2012, after which the majority of the holders of the outstanding 3.50% Senior Convertible Notes elected to convert their notes. The Company issued 864,106 common shares upon conversion, and these shares were included in the calculation of basic weighted-average common shares outstanding for the year ended December 31, 2012. Please refer to Note 5 - Long-term Debt for additional discussion. Prior to calling the 3.50% Senior Convertible Notes for redemption, the Company’s notes had a net-share settlement right giving the Company the option to irrevocably elect, by notice to the trustee under the indenture for the notes, to settle the Company’s obligation, in the event that holders of the notes elected to convert all or a portion of their notes, by delivering cash in an amount equal to each $1,000 principal amount of notes surrendered for conversion and, if applicable, at the Company’s option, shares of common stock or cash, or any combination of common stock and cash, for the amount of conversion value in excess of the principal amount. Prior to the settlement of the Company’s 3.50% Senior Convertible Notes, potentially dilutive shares associated with the conversion feature were accounted for using the treasury stock method when shares of the Company’s common stock traded at an average closing price that exceeded the $54.42 conversion price. Shares of the Company’s common stock traded at an average closing price exceeding the conversion price and were included on an adjusted weighted basis for the portion of the year ended December 31, 2012, for which they were outstanding. Shares of the Company’s common stock traded at an average closing price exceeding the $54.42 conversion price for the twelve-month period ended December 31, 2011, making the 3.50% Senior Convertible Notes dilutive for that period. Shares of the Company's common stock did not trade at an average closing price exceeding the $54.42 conversion price for the year ended December 31, 2010. Therefore, the 3.50% Senior Convertible Notes were not dilutive and did not impact the diluted earnings per share calculation for the year ended December 31, 2010.

The treasury stock method is used to measure the dilutive impact of in-the-money stock options, unvested RSUs, contingent PSUs, and 3.50% Senior Convertible Notes.

The following table details the weighted-average dilutive and anti-dilutive securities related to stock options, RSUs, PSUs, and the 3.50% Senior Convertible Notes for the years presented:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Dilutive	—	3,809	1,720
Anti-dilutive	2,102	—	—

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The following table sets forth the calculations of basic and diluted earnings per share:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands, except per share amounts)		
Net income (loss)	$(54,249)	$215,416	$196,837
Basic weighted-average common shares outstanding	65,138	63,755	62,969
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	—	2,592	1,720
Add: dilutive effect of 3.50% Senior Convertible Notes	—	1,217	—
Diluted weighted-average common shares outstanding	65,138	67,564	64,689
Basic net income (loss) per common share	$(0.83)	$3.38	$3.13
Diluted net income (loss) per common share	$(0.83)	$3.19	$3.04

Comprehensive Income (Loss)

Comprehensive income (loss) is used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of stockholders' equity instead of net income (loss). Comprehensive income (loss) is presented net of income taxes in the accompanying consolidated statements of comprehensive income (loss).

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The changes in the balances of components comprising other comprehensive income (loss) are presented in the following table:

	Change in Derivative Instrument Fair Value (in thousands)	Derivative Reclassification to Earnings	Pension Liability Adjustments
For the year ended December 31, 2010			
Before tax income (loss)	$26,904	$10,608	$(1,570)
Tax benefit (expense)	(10,093)	(3,967)	590
Income (loss), net of tax	$16,811	$6,641	$(980)
For the year ended December 31, 2011			
Before tax income (loss)	$—	$20,707	$(2,779)
Tax benefit (expense)	—	(7,710)	984
Income (loss), net of tax	$—	$12,997	$(1,795)
For the year ended December 31, 2012			
Before tax (loss)	$—	$(3,865)	$(3,909)
Tax benefit	—	1,601	1,439
(Loss), net of tax	$—	$(2,264)	$(2,470)

Fair Value of Financial Instruments

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 recorded value of the Company's credit facility approximates its fair value as it bears interest at a floating rate that approximates a current market rate. The Company had $340.0 million of outstanding loans under its credit facility as of December 31, 2012. The Company had no borrowings outstanding under its credit facility as of December 31, 2011. The Company's 3.50% Senior Convertible Notes, 2019 Notes, 2021 Notes, and 2023 Notes, are recorded at cost, and the fair values are disclosed in Note 11 - Fair Value Measurements. The Company has derivative financial instruments that are recorded at fair value. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Industry Segment and Geographic Information

The Company operates exclusively in the exploration and production segment of the oil and gas industry and all of the Company's operations are conducted entirely in the United States. The Company reports as a single industry segment. The Company's gas marketing function provides mostly internal services and acts as the first purchaser of natural gas and natural gas liquids produced by the Company in certain cases. The Company considers its marketing function as ancillary to its oil and gas producing activities. The amount of income these operations generate from marketing gas produced by third parties is not material to the Company's results of operations, and segmentation of such activity would not provide a better understanding of the Company's performance. However, gross revenue and expense related to marketing activities for gas produced by third parties are presented in the marketed gas system revenue and marketed gas system expense line items in the accompanying statements of operations.

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Off-Balance Sheet Arrangements

The Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. The Company has not been involved in any unconsolidated SPE transactions.

The Company evaluates its transactions to determine if any variable interest entities exist. If it is determined that SM Energy is the primary beneficiary of a variable interest entity, that entity is consolidated into SM Energy.

Recently Issued Accounting Standards

On January 1, 2012, the Company adopted new fair value measurement authoritative accounting guidance issued by the FASB, that clarifies the application of fair value measurement and disclosure requirements and changes particular principles and requirements for measuring fair value. For each class of assets and liabilities not measured at fair value in the Company's financial statements but for which fair value is disclosed, this guidance requires the Company to disclose the nature, characteristics, and risks of the asset or liability and the level of the fair value hierarchy within which the fair value measurement is categorized. Please refer to Note 11 - Fair Value Measurements in which the changes to the Company's financial statements resulting from the new authoritative guidance are presented.

On January 1, 2012, the Company adopted new authoritative accounting guidance issued by the FASB stating an entity that reports items of other comprehensive income has the option to present the components of comprehensive income in either one continuous financial statement or two consecutive financial statements, including reclassification adjustments. The adoption of this statement did not have a material impact on the Company. The Company has elected to present a separate statement of comprehensive income, including the individual components, titled Consolidated Statements of Comprehensive Income (Loss), as part of these financial statements. Additionally, the Company has elected to present the reclassification adjustments under the heading Comprehensive Income (Loss), above.

On September 30, 2012, the Company elected to early adopt new authoritative accounting guidance issued by the FASB, which provided that an entity that tests indefinite-lived intangible assets for impairment has the option to assess qualitative factors to determine whether it is more likely than not that an asset is impaired as a basis for determining whether a quantitative test is necessary. The adoption of this statement did not have a material impact on the Company's financial statements.

There are no new significant accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of December 31, 2012.

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Note 2 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	As of December 31, 2012	2011
	(in thousands)	
Accrued oil, gas, and NGL production revenue	$160,568	$149,384
Amounts due from joint interest owners	42,740	30,784
Receivable due from Mitsui	19,931	—
State severance tax refunds	17,237	14,979
Other	14,329	15,221
Total accounts receivable	$254,805	$210,368

Accounts payable and accrued expenses are comprised of the following:

	As of December 31, 2012	2011
	(in thousands)	
Accrued drilling costs	$243,611	$189,749
Revenue and severance tax payable	65,494	61,613
Accrued lease operating expense	28,037	25,197
Accrued property taxes	9,478	6,994
Joint owner advances	69,639	79,138
Accrued compensation	35,607	43,056
Accrued interest	25,027	14,646
Other	48,734	36,606
Total accounts payable and accrued expenses	$525,627	$456,999

Note 3 – Divestitures and Assets Held for Sale

During 2012, the Company divested of various non-strategic properties located in its Rocky Mountain and Mid-Continent regions for a total of $57.4 million in total divestiture proceeds, before marketing costs, Net Profits Plan payments, and legal fees (referred throughout this report as "divestiture proceeds"). The estimated net gain on these divestitures is $6.9 million. The final sales prices related to these divestitures are subject to normal post-closing adjustments and are expected to be finalized during the first half of 2013. See discussion below regarding the loss on unsuccessful sale of properties, which is included in gain (loss) on divestiture activity in the accompanying statements of operations.

2011 Divestiture Activity

- Eagle Ford Shale Divestiture. In August 2011, the Company divested of certain operated Eagle Ford shale assets located in its South Texas & Gulf Coast region. This divestiture was comprised of the Company's entire operated acreage in LaSalle County, Texas, as well as an immaterial adjacent block of its operated acreage in Dimmit County, Texas. Total divestiture proceeds were $230.7 million. The final gain on this divestiture was $193.8 million. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement for information on additional Eagle Ford activity in 2011.

- Mid-Continent Divestiture. In June 2011, the Company divested of certain non-strategic assets located in its Mid-Continent region. Total divestiture proceeds were $35.8 million. The final gain on this divestiture was $28.5 million.

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- Rocky Mountain Divestiture. In January 2011, the Company divested of certain non-strategic assets located in its Rocky Mountain region. Total divestiture proceeds were $45.5 million. The final gain on this divestiture was $27.2 million.

2010 Divestiture Activity

- Permian Divestiture. In December 2010, the Company completed the divestiture of certain non-strategic assets located in its Permian region. Total divestiture proceeds were $54.7 million. The final gain on this divestiture was $18.4 million.
- Sequel Divestiture. In March 2010, the Company completed the divestiture of certain non-strategic assets located in its Rocky Mountain region. Total divestiture proceeds were $129.1 million. The final gain on this divestiture was $53.1 million. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code").
- Legacy Divestiture. In February 2010, the Company completed the divestiture of certain non-strategic assets located in its Rocky Mountain region. Total divestiture proceeds were $125.3 million. The final gain on this divestiture was $66.7 million. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less costs to sell. Subsequent changes to the estimated fair value less the cost to sell will impact the measurement of assets held for sale for which fair value less costs to sell is determined to be less than the carrying value of the assets.

As of December 31, 2012, the accompanying balance sheets present $33.6 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense. A corresponding asset retirement obligation liability of $1.4 million is separately presented. The assets held for sale include the Company's Marcellus shale assets located in Pennsylvania and certain assets located in the Company's Rocky Mountain region, all of which are recorded at the lesser of their carrying values or their respective fair value less estimated costs to sell. Write-downs to fair value less estimated costs to sell are reflected in the gain (loss) on divestiture activity line item in the accompanying statements of operations.

During 2012, the Company reclassified a portion of the assets previously held for sale to assets held and used, as the assets were no longer being actively marketed. The assets were measured at the lower of the carrying value of the assets before being classified as held for sale, adjusted for any DD&A that would have been recognized had the assets been continuously held and used, or the fair value of the assets at the date they no longer met the criteria as held for sale. As a result of this measurement, the Company recognized $1.7 million of DD&A expense and a $33.9 million loss on unsuccessful sale of properties, which is included in gain (loss) on divestiture activity in the accompanying statements of operations.

Subsequent to December 31, 2012, the Company divested of a portion of its properties located in its Rocky Mountain region that were classified as held for sale at year end. Total divestiture proceeds were $9.2 million. The estimated gain on this divestiture is $2.5 million and is expected to be finalized during the first half of 2013.

The Company determined that neither these planned nor executed asset sales qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

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Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Current portion of income tax benefit (expense)			
Federal	$—	$1,757	$(2,903)
State	(370)	(1,553)	(639)
Deferred portion of income tax benefit (expense)	29,638	(123,789)	(114,517)
Total income tax benefit (expense)	$29,268	$(123,585)	$(118,059)
Effective tax rate	35.0%	36.5%	37.5%

The Company reduces its income tax payable to reflect employee stock option exercises. In 2010, the excess income tax benefit to the Company associated with stock awards was $854,000. There was no excess income tax benefit associated with stock awards in 2012 or 2011.

The components of the net deferred income tax liabilities are as follows:

	As of December 31,	
	2012	2011
	(in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$678,624	$639,485
Unrealized derivative asset	15,942	13,274
Other	6,443	4,129
Total deferred tax liabilities	701,009	656,888
Deferred tax assets:		
Federal and state tax net operating loss carryovers	113,522	23,651
Net Profits Plan liability	29,233	40,148
Stock compensation	18,026	17,728
Pension liability	6,849	5,902
Federal and state tax credit carryovers	5,271	4,301
Other long-term liabilities	4,619	4,908
Total deferred tax assets	177,520	96,638
Valuation allowance	(5,315)	(3,791)
Net deferred tax assets	172,205	92,847
Total net deferred tax liabilities	528,804	564,041
Less: current deferred income tax liabilities	(5,442)	(3,307)
Add: current deferred income tax assets	14,021	7,529
Non-current net deferred tax liabilities	$537,383	$568,263
Current federal income tax refundable	$2,511	$5,581
Current state income tax refundable	$853	$—
Current state income tax payable	$—	$774

At December 31, 2012, the Company estimated its federal net operating loss carryforward at $376.6 million, which includes unrecognized excess income tax benefits associated with stock awards of $93.4 million. The federal net operating loss carryforward begins to expire in 2031. The Company has estimated state net

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operating loss carryforwards of $361.2 million that expire between 2013 and 2032. The Company has claimed federal research and development ("R&D") credit carryforwards of $5.0 million that expire between 2028 and 2031 and other state tax credits of $252,000 that expire between 2013 and 2022. The Company's valuation allowance relates to charitable contribution carryfowards, state net operating loss carryforwards, state tax credits, and state and federal income tax benefit amounts, which the Company anticipates will expire before they can be utilized. Permanent items included in the calculation of income tax for certain states are anticipated to impact the Company's ability to deduct operating losses and realize federal income tax deduction benefits in those states, and the Company adjusts its valuation allowances accordingly. The change in the valuation allowance from 2011 to 2012, indicated below, primarily reflects a change in the Company's position regarding anticipated utilization of charitable contribution carryforward amounts and cumulative net operating losses attributed to Oklahoma.

Federal income tax expense differs from the amount that would be provided by applying the statutory United States federal income tax rate to income before income taxes primarily due to the effect of state income taxes, R&D credits, percentage depletion, changes in valuation allowances, and other permanent differences, as follows:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Federal statutory tax benefit (expense)	$29,231	$(118,652)	$(110,214)
(Increase) decrease in tax resulting from:			
State tax benefit (expense) (net of federal benefit)	992	(6,458)	(7,750)
Research and development credit	970	4,516	—
Change in valuation allowance	(1,524)	(1,627)	1,039
Statutory depletion	210	341	266
Other	(611)	(1,705)	(1,400)
Income tax benefit (expense)	$29,268	$(123,585)	$(118,059)

Acquisitions, divestitures, drilling activity, and basis differentials impacting the prices received for oil, gas, and NGLs affect apportionment of taxable income to the states where the Company owns oil and gas properties. As its apportionment factors change, the Company's blended state income tax rate changes. This change, when applied to the Company's total temporary differences, impacts the total income tax reported in the current year and is reflected in state taxes in the table above. Items affecting state apportionment factors are evaluated at the beginning of each year, after completion of the prior year income tax return, and when significant acquisition, divestiture or changes in drilling activity occurs during the year.

The Company and its subsidiaries file income tax returns in the United States federal jurisdiction and in various states. With certain exceptions, the Company is no longer subject to United States federal or state income tax examinations by these tax authorities for years before 2008. In the third quarter of 2011, the Company completed a multi-year R&D credit study and filed amended federal returns to claim a credit for all open years. Federal tax law allowing for the calculation of an R&D credit for 2012 was not enacted until after December 31, therefore, no 2012 research activities are reflected in the table above.

In the first quarter of 2011, the Company received a $5.5 million refund from its 2006 tax year as a result of a net operating loss carryback claim from the 2008 tax year. In the fourth quarter of 2010, the Internal Revenue Service initiated an audit of the Company for the 2009 tax year. The audit was concluded in the second quarter of 2011 with a nominal decrease to the Company's total 2005 refund claim of $25.0 million. A quick refund claim of $22.9 million from 2005 was received in the third quarter of 2010. The balance was received in the fourth quarter of 2011. The Internal Revenue Service initiated an audit in the first quarter of 2012 for the 2007 and 2010 tax years. This audit was still ongoing at year-end.

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The Company complies with authoritative accounting guidance regarding uncertain tax provisions. The entire amount of unrecognized tax benefit reported by the Company would affect its effective tax rate if recognized. Interest expense in the accompanying statements of operations includes a negligible amount associated with income taxes. In 2011, the Company also recorded a negligible amount of penalty expense associated with income taxes as a general and administrative expense. There were no penalties for 2012 and 2010.

The total amount recorded for unrecognized tax benefits is presented below:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Beginning balance	$1,961	$807	$884
Additions based on tax positions related to current year	—	1,172	—
Additions for tax positions of prior years	317	183	244
Reductions for lapse of statute of limitations	—	(201)	(321)
Ending balance	$2,278	$1,961	$807

Note 5 – Long-term Debt

Revolving Credit Facility

The Company executed a Fourth Amended and Restated Credit Agreement on May 27, 2011. This amended revolving credit facility replaced the Company’s previous facility. The Company incurred $8.7 million of deferred financing costs in association with the amended credit facility. Borrowings under the facility are secured by substantially all of the Company’s proved oil and gas properties. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.0 billion, and a maturity date of May 27, 2016. The borrowing base is subject to regular semi-annual redeterminations by the Company’s lenders. The borrowing base redetermination process considers the value of the Company’s oil and gas properties. On August 31, 2012, the lending group redetermined the Company's reserve-backed borrowing base under the credit facility at an amount of $1.55 billion, an increase from $1.4 billion. The next scheduled re-determination date is April 1, 2013.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including the limitation of the Company’s dividends to no more than $50.0 million per year. The Company was in compliance with all financial covenants under the credit facility as of December 31, 2012, and through the filing date of this report.

Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate plus the applicable margin from the utilization table below, and Alternate Base Rate (“ABR”) and swingline loans accrue interest at Prime plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying statements of operations.

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Loans	1.500 %	1.750 %	2.000 %	2.250 %	2.500 %
ABR Loans or Swingline Loans	0.500 %	0.750 %	1.000 %	1.250 %	1.500 %
Commitment Fee Rate	0.375 %	0.375 %	0.500 %	0.500 %	0.500 %

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The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of February 14, 2013, December 31, 2012, and December 31, 2011.

	As of February 14, 2013	As of December 31, 2012	As of December 31, 2011
	(in millions)		
Credit facility balance	$407.5	$340.0	$—
Letters of credit [1]	$0.8	$0.8	$0.6
Available borrowing capacity	$591.7	$659.2	$999.4

[1] Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis.

3.50% Senior Convertible Notes Due 2027

On April 2, 2012, the Company called for redemption all of its outstanding 3.50% Senior Convertible Notes due 2027 (the "3.50% Senior Convertible Notes"). The call for redemption resulted in holders of $281.3 million aggregate principal amount electing to convert their notes. The Company settled the principal amount of all converted 3.50% Senior Convertible Notes in cash and settled the excess conversion value by issuing 864,106 shares of its common stock. The Company redeemed the remaining $6.2 million of aggregate principal amount of notes that were not converted on the redemption date at par plus accrued interest in cash. The Company used funds borrowed under its credit facility to pay the cash portion of the settlement.

2023 Notes

On June 29, 2012, the Company issued $400.0 million in aggregate principal amount of 6.50% Senior Notes due 2023. The 2023 Notes were issued at par and mature on January 1, 2023. The Company received net proceeds of $392.1 million after deducting fees of $7.9 million, which are being amortized as deferred financing costs over the life of the 2023 Notes. The net proceeds were used to reduce the Company's outstanding credit facility balance.

Prior to July 1, 2015, the Company may redeem, on one or more occasions, up to 35 percent of the aggregate principal amount of the 2023 Notes with the net cash proceeds of certain equity offerings at a redemption price of 106.5% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2023 Notes, in whole or in part, at any time prior to July 1, 2017, at a redemption price equal to 100 percent of the principal amount of the 2023 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after July 1, 2017, the Company may also redeem all or, from time to time, a portion of the 2023 Notes at the redemption prices set forth below, during the twelve-month period beginning on July 1 of each applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2017	103.250	%
2018	102.167	%
2019	101.083	%
2020 and thereafter	100.000	%

The 2023 Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt, and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 2023 Notes. The Company is subject to certain covenants under the indenture governing the 2023 Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends. However, the first $6.5 million of dividends paid each year are not restricted by this covenant. The Company was in compliance with all covenants under its 2023 Notes as of December 31, 2012, and through the filing date of this report.

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Additionally, on June 29, 2012, the Company entered into a registration rights agreement that provides holders of the 2023 Notes certain registration rights under the Securities Act of 1933, as amended (the “Securities Act”). The Company satisfied its obligations to exchange its outstanding $400.0 million 2023 Notes for notes registered under the Securities Act on October 30, 2012.

2021 Notes

On November 8, 2011, the Company issued $350.0 million in aggregate principal amount of 6.50% Senior Notes due 2021. The 2021 Notes were issued at par and mature on November 15, 2021. The Company received net proceeds of $343.1 million after deducting fees of $6.9 million, which are being amortized as deferred financing costs over the life of the 2021 Notes. The net proceeds were used for general corporate purposes and to reduce the Company’s outstanding credit facility balance.

Prior to November 15, 2014, the Company may redeem up to 35 percent of the aggregate principal amount of the 2021 Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.5% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2021 Notes, in whole or in part, at any time prior to November 15, 2016, at a redemption price equal to 100% of the principal amount, plus a specified make-whole premium and accrued and unpaid interest.

The Company may also redeem all or, from time to time, a portion of the 2021 Notes on or after November 15, 2016, at the prices set forth below, during the twelve-month period beginning on November 15 of the applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2016	103.250	%
2017	102.167	%
2018	101.083	%
2019 and thereafter	100.000	%

The 2021 Notes are unsecured senior obligations and rank equal in right of payment with all of the Company’s existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 2021 Notes. The Company is subject to certain covenants under the indenture governing the 2021 Notes that limit incurring additional indebtedness, issuing preferred stock, and making restricted payments, including dividends. The first $6.5 million of dividends paid each year are not restricted by this covenant. The Company was in compliance with all covenants under its 2021 Notes as of December 31, 2012 and through the filing date of this report.

Additionally, on November 8, 2011, the Company entered into a registration rights agreement that provides holders of the 2021 Notes certain registration rights for the 2021 Notes under the Securities Act. The Company satisfied its obligations to exchange its outstanding $350.0 million of its 2021 Notes for notes registered under the Securities Act on March 7, 2012.

2019 Notes

On February 7, 2011, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2019. The 2019 Notes were issued at par and mature on February 15, 2019. The Company received net proceeds of $341.1 million after deducting fees of $8.9 million, which are being amortized as deferred financing costs over the life of the 2019 Notes. The net proceeds were used to repay borrowings under the Company’s previous credit facility, to fund the Company’s ongoing capital expenditure program, and for general corporate purposes.

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Prior to February 15, 2014, the Company may redeem up to 35 percent of the aggregate principal amount of the 2019 Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2019 Notes, in whole or in part, at any time prior to February 15, 2015, at a redemption price equal to 100% of the principal amount, plus a specified make-whole premium and accrued and unpaid interest.

The Company may also redeem all or, from time to time, a portion of the 2019 Notes on or after February 15, 2015, at the prices set forth below, during the twelve-month period beginning on February 15 of the applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.313	%
2016	101.656	%
2017 and thereafter	100.000	%

The 2019 Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 2019 Notes. The Company is subject to certain covenants under the indenture governing the 2019 Notes that limit incurring additional indebtedness, issuing preferred stock, and making restricted payments, including dividends. The first $6.5 million of dividends paid each year are not restricted by this covenant. The Company was in compliance with all covenants under its 2019 Notes as of December 31, 2012 and through the filing date of this report.

Additionally, on February 7, 2011, the Company entered into a registration rights agreement that provides holders of the 2019 Notes certain registration rights for the 2019 Notes under the Securities Act. The Company satisfied its obligations to exchange its outstanding $350.0 million of its 2019 Notes for notes registered under the Securities Act on January 11, 2012.

Capitalized Interest

Capitalized interest costs for the Company for the years ended December 31, 2012, 2011, and 2010, were $12.1 million, $10.8 million, and $4.3 million, respectively.

Note 6 – Commitments and Contingencies

Commitments

The Company has entered into various agreements, which include drilling rig contracts of $91.4 million, gathering, transportation, and processing through-put commitments of $858.7 million, office leases, including maintenance, of $55.3 million, and other miscellaneous contracts and leases of $7.2 million. The annual minimum payments for the next five years and total minimum lease payments thereafter are presented below:

Years Ending December 31,	(in thousands)
2013	$127,753
2014	111,674
2015	99,854
2016	102,540
2017	101,456
Thereafter	469,348
Total	$1,012,625

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The Company has gathering, processing, and transportation through-put commitments with various parties that require delivery of a fixed determinable quantity of product. The aggregate minimum commitment to deliver is 1,515 Bcf of natural gas and 36 MMBbls of oil. These contracts expire at various dates through 2023, and the total amount of the commitment is approximately $858.7 million. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. As of the filing date of this report, the Company does not expect to incur any material shortfalls.

The Company leases office space under various operating leases with terms extending as far as May 31, 2024. Rent expense for 2012, 2011, and 2010 was $5.4 million, $3.7 million, and $2.7 million, respectively. The Company also leases office equipment under various operating leases.

In addition to the amounts in the above table, the Company entered into a capital project commencing in 2011 for the development of midstream infrastructure in the Company's non-operated Eagle Ford shale play. Pursuant to the terms of the agreement for the construction, ownership and operation of these assets, the Company is required to pay its portion of the costs for the next two years. Based on current estimates, the Company does not expect its costs to exceed $67 million during this time.

Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such pending litigation and claims will not have a material effect on the results of operations, the financial position, or the cash flows of the Company.

The Company was a defendant in litigation wherein the plaintiffs claimed an aggregate overriding royalty interest of 7.46875 percent in production from approximately 22,000 of the Company's net acres in the Eagle Ford shale play in South Texas. The plaintiffs sought to quiet title to their claimed overriding royalty interest and to recover unpaid overriding royalty interest proceeds allegedly due. The Company believes that the claimed overriding royalty interest has been terminated under the governing agreements and the applicable law, and has contested the plaintiffs' claims. Both parties filed motions for summary judgment, and on February 8, 2011, the District Court in Webb County, Texas, issued an order granting plaintiffs' motion for summary judgment and denying the Company's motion for summary judgment. On September 30, 2011, the District Court entered final judgment for the plaintiffs and awarded then current damages of approximately $5.1 million, which included prejudgment interest. The District Court also awarded attorneys' fees and costs to the plaintiffs. The Company appealed the District Court's judgment and obtained a stay pending appeal that prevented the plaintiffs from executing on the judgment.

On May 23, 2012, the Fourth Court of Appeals for the State of Texas delivered its opinion in this case, which reversed the summary judgment granted to the plaintiffs by the District Court and rendered judgment that the plaintiffs take nothing. Accordingly, based on the judgment of the Fourth Court of Appeals, the plaintiffs are not entitled to their claimed aggregate 7.46875 percent overriding royalty interest, nor are they entitled to the claimed damages related to the overriding royalty interest, attorneys fees or costs. The plaintiffs filed a petition with the Supreme Court of Texas requesting a review of the Fourth Court of Appeals judgment. The Supreme Court of Texas denied this petition for review on February 15, 2013. As a result, the decision of the Fourth Court of Appeals is dispositive and its dismissal of the plaintiffs' claims is final.

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On January 27, 2011, Chieftain filed a Class Action Petition against the Company in the District Court of Beaver County, Oklahoma, claiming damages related to royalty valuation on all of the Company's Oklahoma wells. These claims include breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. The Company removed this lawsuit to the United States District Court for the Western District of Oklahoma on February 22, 2011. The Company has responded to the petition and denied the allegations. The court has not yet ruled on Chieftain's motion to certify the putative class, and has stayed any such ruling until the United States Court of Appeals for the Tenth Circuit issues its ruling on class certification in two similar royalty class action lawsuits, where the defendants have appealed such certification. The opinion from the Tenth Circuit is expected during the summer of 2013.

This case involves complex legal issues and uncertainties; a potentially large class of plaintiffs, and a large number of related producing properties, lease agreements and wells; and an alleged class period commencing in 1988 and spanning the entire producing life of the wells. Because the proceedings are in the early stages, with substantive discovery yet to be conducted, the Company is unable to estimate what impact, if any, the action will have on its financial condition, results of operations or cash flows. The Company is still evaluating the claims, but believes that it has properly valued and paid royalty under Oklahoma law and has and will continue to vigorously defend this case.

Note 7 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan based on a performance measurement framework whereby selected eligible employee participants may be awarded an annual cash bonus. The plan document provides that no participant may receive an annual bonus under the plan of more than 200 percent of his or her base salary. As the plan is currently administered, any awards under the plan are based on Company and regional performance and are then further refined by individual performance. The Company accrues cash bonus expense based upon the Company’s current year performance. Included in general and administrative and exploration expense in the accompanying statements of operations are $16.3 million, $23.9 million, and $21.6 million of cash bonus expense related to the specific performance years ended December 31, 2012, 2011, and 2010, respectively.

Equity Plan

There are several components to the Company's Equity Plan that are described in this section. Various types of equity awards have been granted by the Company in different periods.

As of December 31, 2012, 1.4 million shares of common stock remained available for grant under the Equity Plan. The issuance of a direct share benefit such as a share of common stock, a restricted share, a RSU, or a PSU counts as 1.43 shares against the number of shares available to be granted under the Equity Plan. Each PSU has the potential to count as 2.86 shares against the number of shares available to be granted under the Equity Plan based on the final performance multiplier. Stock option grants count as one share for each instrument granted against the number of shares available to be granted under the Equity Plan. Stock options were issued out of the St. Mary Land & Exploration Company Stock Option Plan and the St. Mary Land & Exploration Company Incentive Stock Option Plan, both predecessors to the Equity Plan.

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Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants PSUs to eligible employees as a part of its equity incentive compensation program. The PSU factor is based on the Company's performance after completion of a three-year performance period. The performance criteria for the PSUs are based on a combination of the Company's annualized Total Shareholder Return ("TSR") for the performance period and the relative measure of the Company's TSR compared with the annualized TSR of an index comprised of certain peer companies for the performance period. PSUs are recognized as general and administrative and exploration expense over the vesting period of the award.

The fair value of PSUs was measured at the grant date with a stochastic process method using the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the three-year performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility, dividend yield, and risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with a three year vesting period, as well as the volatilities and dividend yields for each of the Company's peers.

Total expense recorded for PSUs was $18.2 million, $19.7 million, and $17.7 million for the years ended December 31, 2012, 2011, and 2010, respectively. As of December 31, 2012, there was $19.6 million of total unrecognized expense related to PSUs, which is being amortized through 2015.

A summary of the status and activity of PSUs is presented in the following table:

	For the Years Ended December 31,					
	2012		2011		2010	
	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year[(1)]	885,894	$ 57.52	1,110,666	$ 39.48	1,069,090	$ 32.52
Granted[(1)]	314,853	$ 51.98	266,282	$ 91.45	387,651	$ 52.35
Vested[(1)]	(493,679)	$ 44.72	(364,172)	$ 35.74	(210,801)	$ 31.18
Forfeited[(1)]	(37,760)	$ 65.35	(126,882)	$ 33.32	(135,274)	$ 34.28
Non-vested at end of year[(1)]	669,308	$ 63.91	885,894	$ 57.52	1,110,666	$ 39.48

(1) The number of awards assumes a one multiplier. The final number of shares of common stock issued may vary depending on the ending three-year performance multiplier, which ranges from zero to two.

The fair value of the PSUs granted in 2012, 2011, and 2010 was $16.4 million, $24.3 million, and $20.3 million for the 2012, 2011, and 2010 grants, respectively. The PSUs granted in 2012 will vest 1/3 on each of the first three anniversary dates of their issuance. PSUs granted prior to 2012 vest 1/7th, 2/7^{ths}, and 4/7^{ths} on the first three anniversary dates of their issuances.

The total fair value of PSUs that vested during the years ended December 31, 2012, 2011, and 2010 was $22.1 million, $13.0 million, and $6.6 million, respectively.

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During the year ended December 31, 2012, the Company settled 609,714 PSUs that were granted in 2009, and which had earned a two-times multiplier, by issuing a net 812,562 shares of the Company's common stock in accordance with the terms of the PSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the remaining 406,866 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs for 2012.

During the year ended December 31, 2011, the Company settled PSUs that were granted in 2008, which earned a 0.8 times multiplier, by issuing a net 206,468 shares of the Company's common stock in accordance with the terms of the PSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, 98,955 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs for 2011.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants RSUs to eligible employees as a part of its equity incentive compensation program. Restrictions and vesting periods for the awards are determined by the Compensation Committee of the Board of Directors and are set forth in the award agreements. Each RSU represents a right for one share of the Company's common stock to be delivered upon settlement of the award at the end of a specified period. RSUs are recognized as general and administrative and exploration expense over the vesting period of the award.

The total expense associated with RSUs for the years ended December 31, 2012, 2011, and 2010, was $9.8 million, $5.3 million, and $7.7 million, respectively. As of December 31, 2012, there was $14.4 million of total unrecognized expense related to unvested RSU awards, which is being amortized through 2015. The Company records compensation expense associated with the issuance of RSUs based on the fair value of the awards as of the date of grant. The fair value of an RSU is equal to the closing price of the Company's common stock on the day of grant.

A summary of the status and activity of non-vested RSUs is presented below:

	For the Years Ended December 31,					
	2012		2011		2010	
	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	308,877	$44.33	333,359	$31.16	407,123	$34.67
Granted	379,332	$49.47	98,952	$72.69	128,865	$40.31
Vested	(166,672)	$32.72	(105,820)	$30.61	(160,398)	$46.30
Forfeited	(25,293)	$51.06	(17,614)	$36.80	(42,231)	$35.43
Non-vested at end of year	496,244	$51.81	308,877	$44.33	333,359	$31.16

The fair value of RSUs granted in 2012, 2011, and 2010 was $18.8 million, $7.2 million, and $5.2 million, respectively. The RSUs granted in 2012 will vest 1/3 on each of the first three anniversary dates of the award. RSUs granted prior to 2012 vest 1/7th, 2/7^{ths}, and 4/7^{ths} on the first three anniversary dates of their issuances.

The total fair value of RSUs that vested during the years ended December 31, 2012, 2011, and 2010, was $5.4 million, $3.2 million, and $7.4 million, respectively.

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During the years ended December 31, 2012, 2011, and 2010, the Company settled 166,670, 105,820, and 160,381 RSUs, respectively. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued net shares of common stock of 116,813, 72,305, and 113,103 for 2012, 2011, and 2010, respectively. The remaining 49,857, 33,515, and 47,278 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs for 2012, 2011, and 2010, respectively.

Stock Option Grants Under the Equity Incentive Compensation Plan

The Company has previously granted stock options under the St. Mary Land & Exploration Company Stock Option Plan and the St. Mary Land & Exploration Company Incentive Stock Option Plan. The last issuance of stock options occurred on December 31, 2004. Stock options to purchase shares of the Company's common stock had been granted to eligible employees and members of the Board of Directors. All options granted under the option plans were granted at exercise prices equal to the respective closing market price of the Company's underlying common stock on the grant dates. All stock options granted under the option plans are exercisable for a period of up to ten years from the date of grant. As of December 31, 2012, there was no unrecognized compensation expense related to stock option awards.

A summary of activity associated with the Company's Stock Option Plans during the last three years is presented in the following table:

	Shares		Weighted - Average Exercise Price	Aggregate Intrinsic Value
For the year ended December 31, 2010				
Outstanding, start of year	1,274,920		$13.31	
Exercised	(346,377	)	$13.77	$11,281,865
Forfeited	(7,778	)	$16.66	
Outstanding, end of year	920,765		$13.11	$42,192,057
Vested and exercisable at end of year	920,765		$13.11	$42,192,057
For the year ended December 31, 2011				
Outstanding, start of year	920,765		$13.11	
Exercised	(412,551	)	$12.19	$24,359,240
Forfeited	—		$—	
Outstanding, end of year	508,214		$13.86	$30,109,110
Vested and exercisable at end of year	508,214		$13.86	$30,109,110
For the year ended December 31, 2012				
Outstanding, start of year	508,214		$13.86	
Exercised	(240,368	)	$12.65	$11,842,575
Forfeited	—		$—	
Outstanding, end of year	267,846		$14.95	$9,983,177
Vested and exercisable at end of year	267,846		$14.95	$9,983,177

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A summary of additional information related to options outstanding as of December 31, 2012, follows:

	Options Outstanding and Exercisable	
Exercise Price[1]	Number Of Options Outstanding and Exercisable	Weighted-Average Remaining Contractual Life
$12.53	33,805	0.25 years
$12.66	28,053	0.75 years
$13.39	17,142	0.81 years
$13.65	35,893	0.50 years
$14.25	104,093	1 year
$20.87	48,860	2 years
Total	267,846	

(1) Exercise price is equal to the weighted average exercise price.

The fair value of options was measured at the date of grant using the Black-Scholes-Merton option-pricing model. Cash flows resulting from excess tax benefits are classified as part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for vested RSUs, settled PSUs, and exercised options in excess of the deferred tax asset attributable to stock compensation costs for such equity awards. The Company recorded $854,000 of excess tax benefits for the year ended December 31, 2010, as cash inflows from financing activities. The Company recorded no excess tax benefits for the years ended December 31, 2012, and December 31, 2011. Cash received from exercises under all share-based payment arrangements for the years ended December 31, 2012, 2011, and 2010, was $3.0 million, $5.0 million, and $4.8 million, respectively.

Director Shares

In 2012, 2011, and 2010, the Company issued 30,486, 21,568, and 24,258 shares, respectively, of the Company's common stock held as treasury shares to its non-employee directors pursuant to the Company's Equity Plan. The Company recorded compensation expense related to these issuances of $1.3 million, $1.2 million, and $781,000 for the years ended December 31, 2012, 2011, and 2010, respectively.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in fair market value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period. All shares issued under the ESPP on or after December 31, 2011, have no minimum restriction period. The ESPP is intended to qualify under Section 423 of the IRC. The Company has 1.3 million shares available under the ESPP for issuance as of December 31, 2012. Shares issued under the ESPP totaled 66,485 in 2012, 41,358 in 2011, and 52,948 in 2010. Total proceeds to the Company for the issuance of these shares were $2.8 million in 2012, $2.3 million in 2011, and $1.7 million in 2010, respectively.

The fair value of ESPP shares was measured at the date of grant using the Black-Scholes-Merton option-pricing model. Expected volatility was calculated based on the Company's historical daily common stock price, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with a six month vesting period.

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The fair value of ESPP shares issued during the periods reported were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,					
	2012		2011		2010	
Risk free interest rate	0.1	%	0.2	%	0.2	%
Dividend yield	0.2	%	0.2	%	0.3	%
Volatility factor of the expected market price of the Company's common stock	47.8	%	36.3	%	46.3	%
Expected life (in years)	0.5 years		0.5 years		0.5 years	

The Company expensed $948,000, $682,000, and $550,000 for the years ended December 31, 2012, 2011, and 2010, respectively, based on the estimated fair value of grants.

401(k) Plan

The Company has a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 60 percent of their base salaries up to the contribution limits established under the IRC. The Company matches each employee's contribution up to six percent of the employee's base salary and may make additional contributions at its discretion. The Company's matching contributions to the 401(k) Plan were $3.5 million, $2.9 million, and $2.5 million for the years ended December 31, 2012, 2011, and 2010, respectively. No discretionary contributions were made by the Company to the 401(k) Plan for any of these years.

Net Profits Plan

Under the Company's Net Profits Plan, all oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Compensation Committee of the Company's Board of Directors and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, 10 percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the 10 percent level. In December 2007, the Board of Directors discontinued the creation of new pools under the Net Profits Plan. As a result, the 2007 pool was the last Net Profits Plan pool established by the Company.

Cash payments made or accrued under the Net Profits Plan that have been recorded as either general and administrative expense or exploration expense are detailed in the table below:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
General and administrative expense	$15,565	$19,326	$19,798
Exploration expense	1,751	2,091	2,633
Total	$17,316	$21,417	$22,431

Additionally, the Company made or accrued cash payments under the Net Profits Plan of $2.3 million, $6.3 million, and $26.1 million for the years ended December 31, 2012, 2011, and 2010, respectively, as a result of divestiture proceeds. The cash payments are accounted for as a reduction in the gain on divestiture activity in the accompanying statements of operations.

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The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. If the Company allocated the change in liability to these specific functional line items, based on the current allocation of actual distributions made by the Company, such expenses or benefits would predominately be allocated to general and administrative expense. The amount that would be allocated to exploration expense is minimal in comparison. Over time, less of the amount distributed relates to prospective exploration efforts as more of the amount distributed is to individuals that have terminated employment and do not provide ongoing exploration support to the Company.

Note 8 – Pension Benefits

The Company has a non-contributory defined benefit pension plan covering substantially all employees who meet age and service requirements (the "Qualified Pension Plan"). The Company also has a supplemental non-contributory pension plan covering certain management employees (the "Nonqualified Pension Plan" and together with the Qualified Pension Plan, the "Pension Plans").

Obligations and Funded Status for Both Pension Plans

The Company recognizes the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligation) of the Company's Pension Plans in the accompanying balance sheets as either an asset or a liability and recognizes a corresponding adjustment to accumulated other comprehensive income, net of tax. The projected benefit obligation is the actuarial present value of the benefits earned to date by plan participants based on employee service and compensation including the effect of assumed future salary increases. The accumulated benefit obligation uses the same factors as the projected benefit obligation but excludes the effects of assumed future salary increases. The Company's measurement date for plan assets and obligations is December 31.

	For the Years Ended December 31,	
	2012	2011
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$29,480	$23,867
Service cost	4,934	3,800
Interest cost	1,374	1,184
Plan amendments	—	170
Actuarial loss	5,467	1,957
Benefits paid	(1,018)	(1,498)
Projected benefit obligation at end of year	40,237	29,480
Change in plan assets:		
Fair value of plan assets at beginning of year	13,940	10,332
Actual return on plan assets	1,952	(176)
Employer contribution	5,380	5,260
Benefits paid	(1,018)	(1,476)
Fair value of plan assets at end of year	20,254	13,940
Funded status at end of year	$(19,983)	$(15,540)

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The Company’s underfunded status for the Pension Plans for the years ended December 31, 2012 and 2011, is $20.0 million and $15.5 million, respectively, and is recognized in the accompanying balance sheets as a portion of other noncurrent liabilities. No plan assets of the Qualified Pension Plan were returned to the Company during the fiscal year ended December 31, 2012. There are no plan assets in the Nonqualified Pension Plan. The plan was amended in 2011 to increase the vesting percent to 40 percent after attaining two years of service and increasing by 20 percent per year until fully vested. The impact of this change in the vesting schedule is reflected in plan amendments in the table above.

Information for Pension Plan with Accumulated Benefit Obligation in Excess of Plan Assets for Both Plans

	As of December 31,	
	2012	2011
	(in thousands)	
Projected benefit obligation	$40,237	$29,480
Accumulated benefit obligation	$29,437	$21,697
Less: Fair value of plan assets	(20,254)	(13,940)
Underfunded accumulated benefit obligation	$9,183	$7,757

Pension expense is determined based upon the annual service cost of benefits (the actuarial cost of benefits earned during a period) and the interest cost on those liabilities, less the expected return on plan assets. The expected long-term rate of return on plan assets is applied to a calculated value of plan assets that recognizes changes in fair value over a five-year period. This practice is intended to reduce year-to-year volatility in pension expense, but it can have the effect of delaying recognition of differences between actual returns on assets and expected returns based on long-term rate of return assumptions. Amortization of unrecognized net gain or loss resulting from actual experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of net periodic benefit cost for a year. If, as of the beginning of the year, the unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation and the market-related value of plan assets, then the amortization is the excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.

Pre-tax amounts not yet recognized in net periodic pension costs, but rather recognized in accumulated other comprehensive loss as of December 31, 2012, and 2011, consist of:

	As of December 31,	
	2012	2011
	(in thousands)	
Unrecognized actuarial losses	$12,427	$8,501
Unrecognized prior service costs	153	170
Unrecognized transition obligation	—	—
Accumulated other comprehensive loss	$12,580	$8,671

The estimated net loss that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is $876,000.

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Pre-tax changes recognized in other comprehensive income (loss) during 2012, 2011, and 2010, were as follows:

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Net actuarial gain (loss)	$(4,680)	$(3,014)	$(1,937)
Prior service cost	—	(170)	—
Less: Amortization of:			
Prior service cost	(17)	—	—
Actuarial loss	(754)	(405)	(367)
Total other comprehensive income (loss)	$(3,909)	$(2,779)	$(1,570)

Components of Net Periodic Benefit Cost for Both Pension Plans

	For the Years Ended December 31,		
	2012	2011	2010
	(in thousands)		
Components of net periodic benefit cost			
Service cost	$4,934	$3,800	$3,392
Interest cost	1,374	1,184	1,120
Expected return on plan assets that reduces periodic pension cost	(1,165)	(880)	(638)
Amortization of prior service cost	17	—	—
Amortization of net actuarial loss	754	405	367
Net periodic benefit cost	$5,914	$4,509	$4,241

Gains and losses in excess of 10 percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Pension Plan Assumptions

Weighted-average assumptions to measure the Company’s projected benefit obligation and net periodic benefit cost are as follows:

	As of December 31,		
	2012	2011	2010
Projected benefit obligation			
Discount rate	3.9%	4.7%	5.3%
Rate of compensation increase	6.2%	6.2%	6.2%
Net periodic benefit cost			
Discount rate	4.7%	5.3%	6.1%
Expected return on plan assets	7.5%	7.5%	7.5%
Rate of compensation increase	6.2%	6.2%	6.2%

The Company’s pension investment policy includes various guidelines and procedures designed to ensure that assets are prudently invested in a manner necessary to meet the future benefit obligation of the Pension Plans. The policy does not permit the direct investment of plan assets in the Company’s securities. The Qualified Pension Plan's investment horizon is long-term and accordingly the target asset allocations encompass a strategic, long-term

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perspective of capital markets, expected risk and return behavior and perceived future economic conditions. The key investment principles of diversification, assessment of risk, and targeting the optimal expected returns for given levels of risk are applied.

The Qualified Pension Plan's investment portfolio contains a diversified blend of investments, which may reflect varying rates of return. The investments are further diversified within each asset classification. This portfolio diversification provides protection against a single security or class of securities having a disproportionate impact on aggregate investment performance. The actual asset allocations are reviewed and rebalanced on a periodic basis to maintain the target allocations. The weighted-average asset allocation of the Qualified Pension Plan is as follows:

	Target		As of December 31,			
Asset Category	2013		2012		2011	
Equity securities	44.0	%	42.7	%	61.8	%
Debt securities	33.0	%	32.8	%	37.7	%
Other	23.0	%	24.5	%	0.5	%
Total	100.0	%	100.0	%	100.0	%

There is no asset allocation of the Nonqualified Pension Plan since there are no plan assets in that plan. An expected return on plan assets of 7.5 percent was used to calculate the Company’s obligation under the Qualified Pension Plan for 2012 and 2011. Factors considered in determining the expected rate of return include the long-term historical rate of return provided by the equity and debt securities markets and input from the investment consultants and trustees managing the plan assets. The difference in investment income using the projected rate of return compared to the actual rates of return for the past two years was not material and will not have a material effect on the accompanying statements of operations or cash flows from operating activities in future years.

Fair Value Assumptions

The fair value of the Company’s Qualified Pension Plan assets as of December 31, 2012, utilizing the fair value hierarchy discussed in Note 11 – Fair Value Measurements is as follows:

	Actual Asset Allocation		Total	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
				(in thousands)		
Cash and Money Market Funds	3.8	%	$778	$778	$—	$—
Equity Securities						
Domestic (1)	29.2	%	5,920	5,920	—	—
International (2)	13.5	%	2,740	2,740	—	—
Total Equity Securities	42.7	%	8,660	8,660	—	—
Fixed Income Securities						
High-Yield Bonds (3)	6.1	%	1,240	1,240	—	—
Core Fixed Income (4)	20.8	%	4,204	4,204	—	—
Floating Rate Corp Loans (5)	5.9	%	1,186	1,186	—	—
Total Fixed Income Securities	32.8	%	6,630	6,630	—	—
Other Securities:						
Commodities (6)	3.3	%	669	669	—	—
Real Estate (7)	3.9	%	783	—	—	783
Hedge Fund (8)	13.5	%	2,734	1,133	—	1,601
Total Other Securities	20.7	%	4,186	1,802	—	2,384
Total Investments	100.0	%	$20,254	$17,870	$—	$2,384

(1) Equity securities of United States large and small capitalization companies, which are actively traded securities that can be sold upon demand.

(2) International equity securities consists of a well-diversified portfolio of holdings of mostly large issuers organized in developed countries with liquid markets, commingled with investments in equity securities of issuers located in emerging markets and believed to have strong sustainable financial productivity at attractive valuations.

(3) High-yield bonds consist of non-investment grade fixed income securities. The investment objective is to obtain high current income. Due to the increased level of default risk, security selection focuses on credit-risk analysis.

(4) The objective is to achieve value added from sector or issue selection by constructing a portfolio to approximate the investment results of the Barclay's Capital Aggregate Bond Index with a modest amount of variability in duration around the index.

(5) Investments consist of floating rate bank loans. The interest rates on these loans are typically reset on a periodic basis to account for changes in the level of interest rates.

(6) Investments with exposure to commodity price movements, primarily through the use of futures, swaps and other commodity-linked securities.

(7) The investment objective of direct real estate is to provide current income with the potential for long-term capital appreciation. Ownership in real estate entails a long-term time horizon, periodic valuations, and potentially low liquidity.

(8) The hedge fund portfolio includes an investment in an actively traded global mutual fund that focuses on alternative investments and a hedge fund of funds that invests both long and short using a variety of investment strategies.

Included below is a summary of the changes in Level 3 plan assets (in thousands):

December 31, 2011	$—
Purchases	2,329
Investment Returns	55
December 31, 2012	$2,384

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The fair value of the Company’s pension plan assets as of December 31, 2011, is as follows:

	Actual Asset Allocation	Total	Fair Value Measurements Using: Leve