SM Energy Co
Form 10-K
February 19, 2014

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, 2013
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 65,508,073 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 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, of $59.98 per share, as reported on the New York Stock Exchange; was $3,929,174,219. 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 12, 2014, the registrant had 67,056,441 shares of common stock outstanding, which is net of 22,412 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 2014 annual meeting of stockholders to be filed within 120 days after December 31, 2013.

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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 stockholders 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.

At year-end 2012, our reserves shifted from being majority gas to majority liquids. As a result, we now report equivalent volumes and per-unit metrics on a BOE basis rather than on an MCFE basis. Prior year volumes have been conformed to current year presentation.

Significant Developments in 2013

- Resource Play Delineation and Development Results in Record Production and Record Year-End Proved Reserve Estimates. Our estimated proved reserves increased 46 percent to 428.7 MMBOE at December 31, 2013, from 293.4 MMBOE at December 31, 2012. We added 195.5 MMBOE through drilling activities during the year, which was led by our efforts in the Eagle Ford shale in South Texas and the Bakken/Three Forks plays in North Dakota. We also achieved record levels of production in 2013. Our average daily production was composed of 38.2 MBbl of oil, 409.2 MMcf of gas, and 26.0 MBbl of NGLs for an average equivalent production rate of 132.4 MBOE per day, which was an increase of 33 percent from an average of 99.7 MBOE per day in 2012. Costs incurred in 2013 for drilling and exploration activities and acquisitions remained essentially flat compared to 2012 at $1.7 billion. Please refer to Core Operational Areas below for additional discussion concerning our 2013 estimated proved reserves, production, and capital investment.

- Divestiture Activity. We continuously look to improve the quality of our asset portfolio through the divestiture of non-strategic properties. Our divestiture activity helps to generate cash that can be used to fund the acquisition or development of assets with higher potential value. During 2013, we sold a total of 18.2 MMBOE of reserves. We received $445.8 million in total cash proceeds at closing (referred throughout this report as "divestiture proceeds") from these divestitures of non-strategic properties, with the sale of our Anadarko Basin assets in December 2013 being the most significant transaction.
- Impairments. We recorded impairment of proved properties expense of $172.6 million for the year ended December 31, 2013. The impairments in 2013 were a result of negative engineering revisions on Mississippian limestone assets in our Permian region at the end of the year, a plugging and abandonment program of our Olmos interval, dry gas assets in our South Texas & Gulf Coast region, and our decision to no longer pursue the development of certain under-performing assets during the year.

Outlook for 2014

We enter 2014 with a projected $1.9 billion capital program, approximately $1.7 billion of which we expect to allocate to drilling and completion activities with the remaining being allocated to the construction of facilities, land acquisitions, exploration overhead, and geological and geophysical costs. Our proposed 2014 capital program allocates the majority of drilling and completion capital to oil and liquids-rich programs. Please refer to Core Operational Areas below and Outlook for 2014 under Part II, Item 7 of this report for additional discussion surrounding our capital plans for 2014.

Core Operational Areas

Our operations are concentrated in four onshore operating areas in the United States. The following table summarizes estimated proved reserves, PV-10 reserve value, production, and costs incurred in oil and gas activities for the year ended December 31, 2013, for our core operating areas:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total (1)
Proved Reserves					
Oil (MMBbl)	50.6	64.0	11.8	0.2	126.6
Gas (Bcf)	947.3	72.1	26.9	142.9	1,189.3
NGLs (MMBbl)	102.7	—	—	1.2	103.9
MMBOE (1)	311.2	76.0	16.3	25.2	428.7
Relative percentage	73 %	18 %	4 %	6 %	100 %
Proved Developed %	42 %	59 %	91 %	78 %	49 %
PV-10 Values (in millions) (2)					
Proved Developed	$1,989.3	$1,306.5	$435.7	$167.1	$3,898.6
Proved Undeveloped	1,122.6	462.7	26.9	17.7	1,629.9
Total Proved	$3,111.9	$1,769.2	$462.6	$184.8	$5,528.5
Relative percentage	56 %	32 %	8 %	3 %	100 %
Production					
Oil (MMBbl)	5.2	6.4	1.8	0.5	13.9
Gas (Bcf)	98.5	5.8	3.6	41.4	149.3
NGLs (MMBbl)	9.2	—	—	0.2	9.5
MMBOE (1)	30.9	7.4	2.4	7.7	48.3
Avg. Daily Equivalents (MBOE/d)	84.7	20.3	6.5	21.0	132.4
Relative percentage	64 %	15 %	5 %	16 %	100 %
Costs Incurred (in millions)(3)	$849.4	$474.7	$275.7	$91.9	$1,721.1

(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.

(3) Amounts do not sum to total costs incurred due to certain costs relating to our new venture projects being excluded from the regional table above.

South Texas & Gulf Coast Region. Operations in our South Texas & Gulf Coast region are managed from our office in Houston, Texas. Our current development activities 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, 2013, we had approximately 189,000 net acres in the play. We operate approximately 145,000 of these net acres, with a working interest of 100 percent. We believe we have secured the requisite services, such as gas pipeline takeaway capacity and drilling and completion services, to support our current operated development plans.

We continued to acquire acreage in our new venture play in East Texas in 2013, bringing our total acreage position to approximately 215,000 net acres. The Austin Chalk, Woodbine, and Eagle Ford intervals are present across our acreage. We intend to devote capital in 2014 to test a number of geologic concepts in this new venture play.

Nearly all capital deployed in our South Texas & Gulf Coast region in 2013 targeted our operated Eagle Ford shale program and our exploration program in East Texas. Production in 2013 increased 65 percent from the 18.8 MMBOE produced in 2012. Estimated proved reserves at year-end 2013 increased 73 percent from 179.9 MMBOE at year-end 2012. We added approximately 162.6 MMBOE of estimated proved reserves through drilling activities. The increase in production and proved reserves reflects the success we are having in our Eagle Ford shale program and is a result of our ongoing investment and development in this area. Our capital expenditures in our South Texas & Gulf Coast region increased slightly from $848.4 million in 2012 to $849.4 million in 2013. During 2012 and 2013, we were 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"). We expect the total carry amount to be exhausted in early 2014. Please refer to Note 12 - Acquisition and Development Agreement for additional discussion.

Rocky Mountain Region. Operations in our Rocky Mountain region are managed from our office in Billings, Montana. Our development activities in 2013 primarily targeted the Bakken/Three Forks formations in the North Dakota portion of the Williston Basin in our Gooseneck and Raven/Bear Den areas, where we have approximately 79,000 net acres. In 2013, we focused on infill drilling in these areas to optimize development through pad drilling.

We have an emerging resource play in the Powder River Basin. During the second quarter of 2013, we closed an acquisition of approximately 40,000 net acres that is prospective for the Frontier and Shannon formations. We also traded out of the North DJ Basin and received 33,000 net acres in our core area in the Powder River Basin. We now have approximately 140,000 total net acres in the basin. During 2013, several delineation wells were drilled across our acreage position with encouraging results.

Capital expenditures in our Rocky Mountain region increased from $406.8 million in 2012 to $474.7 million in 2013, largely as a result of our Powder River Basin acquisition. Estimated proved reserves for the region at the end of 2013 increased 35 percent from 56.3 MMBOE at year-end 2012. During the year, we added approximately 25.0 MMBOE of proved reserves in this region through drilling activities. Total regional production for 2013 increased 20 percent from the 6.2 MMBOE produced in 2012. The increase in production and proved reserves reflects the continued development activity in our Bakken/Three Forks program.

Permian Region. Operations in our Permian region are managed from our office in Midland, Texas. Our Permian region covers western Texas and southeastern New Mexico. During 2013, we acquired additional acreage in the Midland Basin, bringing our Permian Basin acreage total to approximately 130,000 net acres. Nearly all of the aforementioned acreage is located in the Midland Basin, which we believe is prospective for various shale targets, including the Wolfcamp shale. In the first half of 2013, we executed a delineation program in our Tredway prospect, which focused on a Mississippian limestone target. As we transitioned to the second half of the year, our focus moved to Wolfcamp drilling on our Sweetie Peck acreage, where we expect higher and more consistent returns.

Our capital expenditures in our Permian region increased to $275.7 million in 2013 compared to $232.5 million in 2012, due to an increase in expenditures on our drilling program. The region's 2013 production was 2.4 MMBOE, compared to 2012 production of 1.9 MMBOE. Estimated proved reserves at the end of 2013 were 16.3 MMBOE, which was an increase from 2012 year-end proved reserves of 15.8 MMBOE.

Mid-Continent Region. Operations in our Mid-Continent region are managed from our office in Tulsa, Oklahoma. Our Mid-Continent region manages our assets in the Haynesville shale and Woodford shale. Although gas prices improved in 2013, we reduced activity in our Mid-Continent region, which resulted in a decrease in our 2013 capital expenditures and production. In December 2013, we closed the previously announced divestiture of our Anadarko Basin assets, including our interests in the Granite Wash interval, and an additional package of non-operated Cotton Valley assets. The divestiture of these two asset packages resulted in decreased year-end reserves, as further discussed below.

In 2013, we incurred costs of $91.9 million in our Mid-Continent region for exploration, development, and acquisition activities, compared to $168.2 million incurred in 2012. In 2013, our Mid-Continent region's production was 7.7 MMBOE, a decrease from the 9.7 MMBOE produced in 2012. Estimated proved reserves at the end of 2013 decreased 39 percent from 41.4 MMBOE at the end of 2012.

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, 2013. We engaged Ryder Scott Company, L.P. ("Ryder Scott") to audit 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, 2013, were $96.94 per Bbl for oil, $3.67 per MMBtu for natural gas, and $40.29 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 critical to us. 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.

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 and production business.

	As of December 31,					
	2013		2012		2011	
Reserve data:						
Proved developed						
Oil (MMBbl)	70.2		58.8		50.3	
Gas (Bcf)	569.2		483.2		451.2	
NGLs (MMBbl)	43.8		27.2		15.2	
MMBOE (1)	208.9		166.5		140.7	
Proved undeveloped						
Oil (MMBbl)	56.3		33.5		21.4	
Gas (Bcf)	620.1		350.2		212.8	
NGLs (MMBbl)	60.2		35.1		12.3	
MMBOE (1)	219.9		126.9		69.2	
Total Proved (1)						
Oil (MMBbl) (1)	126.6		92.2		71.7	
Gas (Bcf) (1)	1,189.3		833.4		664.0	
NGLs (MMBbl) (1)	103.9		62.3		27.5	
MMBOE (1)	428.7		293.4		209.9	
Proved developed reserves %	49	%	57	%	67	%
Proved undeveloped reserves %	51	%	43	%	33	%
Reserve value data (in millions):						
Proved developed PV-10	$3,898.6		$2,982.6		$2,836.3	
Proved undeveloped PV-10	1,629.9		866.5		624.9	
Total proved PV-10	$5,528.5		$3,849.1		$3,461.2	
Standardized measure of discounted future cash flows	$4,009.4		$3,021.0		$2,580.0	
Reserve replacement – drilling, excluding revisions	405	%	411	%	310	%
All in – including sales of reserves	380	%	329	%	262	%
All in – excluding sales of reserves	418	%	337	%	317	%
Reserve life (years)	8.9		8.0		7.4	

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

The following table reconciles the standardized measure of discounted future net cash flows (GAAP) to the PV-10 value (Non-GAAP) of total proved reserves. The PV-10 value measure excludes 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, 2013 (in millions)	2012	2011
Standardized measure of discounted future net cash flows	$4,009.4	$3,021.0	$2,580.0
Add: 10 percent annual discount, net of income taxes	2,500.6	1,742.1	1,727.6
Add: future undiscounted income taxes	2,722.2	1,609.4	1,740.4
Undiscounted future net cash flows	9,232.2	6,372.5	6,048.0
Less: 10 percent annual discount without tax effect	(3,703.7)	(2,523.4)	(2,586.8)
PV-10 value	$5,528.5	$3,849.1	$3,461.2

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 proved 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, 2013, we had no undrilled proved undeveloped reserves that had been on our books in excess of five years.

For locations that are more than one location removed from producing developed locations, we utilized reliable geologic and engineering technology to add approximately 40.4 MMBOE of proved undeveloped reserves in the more developed portions of our Eagle Ford shale position and 0.9 MMBOE of proved undeveloped reserves in the more developed portions of our Bakken shale position. We incorporated public and proprietary data from multiple sources to establish geologic continuity of each formation and their 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, 2013, we had 219.9 MMBOE of proved undeveloped reserves, which is an increase of 93.0 MMBOE, or 73 percent, over proved undeveloped reserves of 126.9 MMBOE at December 31, 2012. We added 151.6 MMBOE of proved undeveloped reserves through our drilling program, 105.2 MMBOE of which were extensions and discoveries, primarily in our Eagle Ford shale play, as well as an additional 46.4 MMBOE of infill proved undeveloped reserves primarily in our assets in the Bakken/Three Forks and Eagle Ford shale plays. A negative price revision of 1.7 MMBOE was primarily due to slightly lower reserves in our Eagle Ford shale assets in our South Texas & Gulf Coast region as a result of our election to reject ethane as allowed under our contracts. We realize higher overall net value by rejecting ethane. We had a positive performance revision of 2.9 MMBOE primarily related to improved performance in our operated Eagle Ford shale assets. We removed 2.8 MMBOE of proved undeveloped reserves from our books as a result of the SEC's five-year limitation on the number of years that proved undeveloped reserves may be booked without being developed. During the year, we sold a total of 1.0 MMBOE proved undeveloped reserves in our Mid-Continent and Rocky Mountain regions. During 2013, we converted 56.0 MMBOE of proved undeveloped reserves to proved developed reserves, primarily in our Eagle Ford shale and Bakken/Three Forks plays. During 2013, a total of $562.9 million was spent on projects associated with reserves that were carried as proved undeveloped reserves at the end of 2012. Please refer to Note 12 - Acquisition and Development Agreement for discussion of the carry of certain drilling and completion costs in our outside operated Eagle Ford program. As of December 31, 2013, estimated future development costs relating to our proved undeveloped reserves were approximately $1.2 billion, $980 million, and $355 million in 2014, 2015, and 2016, respectively.

Internal Controls Over Proved 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 our 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 proved 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 an Advising Senior Vice President who received a Bachelor of Science degree in Chemical Engineering from Purdue University in 1979 and a Master of Science Degree in Chemical Engineering from the University of California, Berkeley, in 1981. He is a registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers, and the Society of Petroleum Evaluation Engineers. The Ryder Scott 2013 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 processes and findings.

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 derivative contract settlements. Also presented is a summary of related production costs per BOE.

	For the Years Ended December 31,		
	2013	2012	2011
Net production			
Oil (MMBbl)	13.9	10.4	8.1
Gas (Bcf)	149.3	120.0	100.3
NGLs (MMBbl)	9.5	6.1	3.5
MMBOE (2)	48.3	36.5	28.3
Eagle Ford net production(1)			
Oil (MMBbl)	5.1	3.1	2.5
Gas (Bcf)	97.1	58.1	32.9
NGLs (MMBbl)	9.2	5.7	3.1
MMBOE (2)	30.5	18.5	11.1
Average net daily production			
Oil (MBbl per day)	38.2	28.3	22.1
Gas (MMcf per day)	409.2	328.0	274.8
NGLs (MBbl per day)	26.0	16.7	9.6
MBOE per day (2)	132.4	99.7	77.5
Eagle Ford average net daily production(1)			
Oil (MBbl per day)	14.1	8.6	6.8
Gas (MMcf per day)	265.9	158.8	90.1
NGLs (MBbl per day)	25.2	15.5	8.6
MBOE per day (2)	83.6	50.5	30.4
Realized price			
Oil (per Bbl)	$91.19	$85.45	$88.23
Gas (per Mcf)	$3.93	$2.98	$4.32
NGLs (per Bbl)	$35.95	$37.61	$53.32
Per BOE	$45.50	$40.39	$47.10
Production costs per BOE			
Lease operating expense	$4.82	$4.93	$5.30
Transportation costs	$5.34	$3.81	$3.05
Production taxes	$2.19	$2.00	$1.90

(1) In each of the years 2013, 2012, and 2011, total estimated proved reserves attributed to our Eagle Ford shale properties exceeded 15 percent of our total proved reserves expressed on an equivalent basis.

(2) Amounts may not recalculate due to rounding.

Productive Wells
As of December 31, 2013, we had working interests in 1,061 gross (634 net) productive oil wells and 2,293 gross (916 net) productive gas wells. Productive wells are either wells producing in commercial quantities or wells 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; such designation may not be indicative of current production.

Drilling and Completion Activity
All of our drilling and completion activities are conducted using independent contractors. We do not own any drilling or completion equipment. The following table summarizes the number of operated and non-operated wells drilled and completed or recompleted on our properties in 2013, 2012, and 2011, excluding non-consented projects, active injector wells, salt water disposal wells, and any wells in which we own only a royalty interest:

	For the Years Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	154	75.4	127	47.2	125	32.1
Gas	443	162.5	337	124.5	273	81.0
Non-productive	10	8.5	10	6.3	11	4.0
	607	246.4	474	178.0	409	117.1
Exploratory wells:						
Oil	6	5.1	9	6.9	16	6.3
Gas	4	2.4	8	6.8	48	8.6
Non-productive	1	0.3	8	6.8	3	1.0
	11	7.8	25	20.5	67	15.9
Total	618	254.2	499	198.5	476	133.0

A productive well is an exploratory, development, or extension well that is producing or capable of commercial production of oil, gas, and/or NGLs. 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 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.

In addition to the wells drilled and completed in 2013 (included in the table above), as of February 12, 2014, we were participating in the drilling of 34 gross wells. We operate 18 of these wells on a gross basis (15 on a net basis) and other companies operate the remaining 16 gross wells (three on a net basis). With respect to completion activity, at such date, there were 284 gross wells in which we have an interest that were being completed. We operate 35 of these completion activities on a gross basis (31 on a net basis), and were participating in 249 gross (45 net) non-operated completion activities. Substantially all of these operations relate to the drilling and completion 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, 2013. Undeveloped acreage includes leasehold interests that contain proved undeveloped reserves.

	Developed Acres (1)		Undeveloped Acres (2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	51,093	19,212	32,559	30,081	83,652	49,293
Montana	56,214	38,050	278,481	191,583	334,695	229,633
Nevada	—	—	197,634	197,634	197,634	197,634
North Dakota	155,150	107,170	68,960	37,049	224,110	144,219
Oklahoma	45,550	26,034	47,655	22,932	93,205	48,966
Texas	270,403	156,579	724,997	432,246	995,400	588,825
Wyoming	49,604	23,695	329,663	244,701	379,267	268,396
Other (3)	4,872	2,451	55,736	40,955	60,608	43,406
	632,886	373,191	1,735,685	1,197,181	2,368,571	1,570,372
Louisiana Fee Properties	10,499	10,499	14,415	14,415	24,914	24,914
Louisiana Mineral Servitudes	7,426	4,217	4,528	4,166	11,954	8,383
	17,925	14,716	18,943	18,581	36,868	33,297
Total (4)	650,811	387,907	1,754,628	1,215,762	2,405,439	1,603,669

(1) Developed acreage is acreage assigned to producing wells for the state approved spacing unit for the producing formation in each respective state. 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, Pennsylvania, and Utah.

(4) As of the filing date of this report, we had 72,858, 174,694, and 170,314 net acres scheduled to expire by December 31, 2014, 2015, and 2016, respectively, if production is not established or we take no other action to extend the terms of the applicable lease or leases.

Delivery Commitments

As of December 31, 2013, 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 1,807 Bcf of natural gas and 53 MMBbl 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 or through arranging for the delivery of third party gas. Therefore, we currently do not expect any significant shortfalls.

Major Customers

During 2013, we had three major customers, Regency Gas Services LLC, Anadarko Petroleum Corporation (“Anadarko”), and Plains Marketing LP, which accounted for approximately 26 percent, 16 percent, and 12 percent, respectively, of our total production revenue. During the third quarter of 2013, we entered into various marketing agreements with Anadarko, whereby we are subject to certain gathering, transportation, and processing through-put commitments for up to 10 years pursuant to each contract. While Anadarko is the first purchaser under these contracts, we also share with Anadarko the risk of non-performance by Anadarko’s counterparty purchasers. Several of Anadarko’s counterparty purchasers under these contracts are also direct purchasers of products produced by us.

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, we had one major customer, Regency Gas Services LLC, which accounted for approximately 18 percent of our total production revenue.

Employees and Office Space

As of February 12, 2014, we had 793 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.

The following table summarizes the approximate square footage of office space leased or owned by us, as of December 31, 2013:

Location	Approximate Square Footage
Leased Office Space:	
Denver, CO	95,000
Houston, TX	62,000
Tulsa, OK	56,000
Midland, TX	22,000
Billings, MT	44,000
Williston & Watford City, ND	7,000
Casper, WY	4,000
Huntsville, TX	3,000
Total Leased Office Space	293,000

In addition to the leased office space in the table above, we own a total of 24,000 square feet of office space across all four of our operating regions.

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. Most 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 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 foundation for development activities that we expect to fuel 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 gathering, processing or refining operations, market refined products, own drilling rigs or other equipment, or generate electricity.

We also compete with other oil and gas companies in securing drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells. Consequently, we may face shortages, delays or increased costs 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 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 controlled 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.

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.

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 may result in more stringent permitting, waste handling, disposal and cleanup requirements for the oil and natural gas industry and could have a significant impact on our operating costs.

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 were 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, pay fines, 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.

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 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 operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on these species. It is also possible that a federal or state agency could order a complete halt to 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, completion and production 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.

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 most 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, including saltwater disposal 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, which could result in additional 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.

Environmental, Health and Safety Initiatives. We are committed to conducting our business in a manner that protects the environment and the health and safety of our employees, contractors and the public. We set annual goals for our environmental, health and safety program focused on reducing the number of safety related incidents that occur and the number and impact of spills of produced fluids. We also periodically conduct regulatory compliance audits of our operations to ensure our compliance with all regulations and provide appropriate training for our employees. Reducing air emissions as a result of leaks, venting or flaring of natural gas during operations has become a major focus area for regulatory efforts and for our compliance efforts. While flaring is sometimes necessary, releases of natural gas to the environment and flaring is an economic waste and reducing these volumes is a priority for us. To avoid flaring where possible, we restrict testing periods and make every effort to ensure that our production is connected to gas pipeline infrastructure as quickly as possible after well completions. During this last year, we also cooperated with other producers in North Dakota in the ongoing development of recommendations to reduce the amount of flaring that is occurring there as a result of area wide infrastructure limitations that are beyond our control. Another focus for our environmental effort has been reduction of water use through recycling of flowback water in South Texas for use as frac fluid. We have incurred in the past, and expect to incur in the future, capital costs related to environmental compliance. Such expenditures are included within our overall capital budget and are not separately itemized.

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 (the “Securities Act”) 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, similar expressions are 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;
- 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. Some of these risks are described in the Risk Factors section of this Form 10-K, 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;
- 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 develop and/or 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 outside 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 service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver necessary quantities of natural gas or crude oil to contractual counterparties;
- 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;
- the possibility that covenants in our debt agreements may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions or lead to the accelerated payment of our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of seasonal weather conditions and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental and other applicable rules;
- 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 legislation and 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 Conflict of Interest Policy, 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.

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 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 liquid volume, used in reference to oil or other liquid hydrocarbons.

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

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 and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir beyond its known horizon.

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 or stratigraphic condition.

Finding and development cost. Expressed in dollars per BOE. 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 and analysts. 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 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, acquisitions, and revisions of previous estimates, 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.

Frac spread. Hydraulic fracturing requires custom-designed and purpose-built equipment. A “spread” is the equipment necessary to carry out a fracturing job.

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.

MBOE. One thousand barrels of oil equivalent.

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

MCFE. 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.

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

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.
MMcf. One million cubic feet, used in reference to natural gas.
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, butane, and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
NYMEX WTI. New York Mercantile Exchange West Texas Intermediate, a common industry benchmark price for crude oil.
OPIS. Oil Price Information Service Mont Belvieu, a common industry benchmark for NGL pricing.
PV-10 value (Non-GAAP). The present value of estimated future 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 of 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.

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 and analysts. 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, 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, 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 lower expected geological 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.

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, natural gas, and associated liquids 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. The applicable SEC definition of undeveloped reserves provides that 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.

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 imports and exports 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.

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.

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

In recent years, the United States and global economies and financial systems have experienced turmoil and upheaval characterized by extreme volatility in prices of equity and debt securities, periods of 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 the United States economy appears to have stabilized and may be recovering, the extent and timing of a recovery, and whether it can be sustained, are uncertain. Renewed weakness in the United States or other large economies could materially adversely affect our business and financial condition. For example:

- 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, leading to lower revenues, which 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 the exploration and/or development of 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. Without successful drilling or acquisition activities, our reserves and production will decline over time. In addition, competition for crude oil and natural gas properties is intense, and many of our competitors have financial, technical, human, and other resources necessary 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 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.

Substantial capital is required to develop and 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 may reduce our planned 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, 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 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 exploratory and 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 properties. We may not be successful in acquiring and developing profitable properties in the face of this competition. In addition, other companies may have a greater ability to continue drilling activities during periods of low natural gas or oil prices and to absorb the burden of current and future governmental regulations and taxation. 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. Also, we 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. Our inability to compete effectively with companies in any area of our business could have a material adverse impact on our business activities, financial condition and results of operations.

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 and/or amount 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, which we may not control.

As of December 31, 2013, 51 percent, or 219.9 MMBOE, of our estimated proved reserves were proved undeveloped, and three percent, or 10.9 MMBOE, were proved developed non-producing. In order to develop our proved undeveloped reserves, as of December 31, 2013, we estimate approximately $2.8 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, 2013, we estimate capital expenditures of approximately $29 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.

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, 2013, were estimated using a calculated 12-month average sales price of $3.67 per MMBtu of natural gas (NYMEX Henry Hub spot price), $96.94 per Bbl of oil (NYMEX WTI spot price), and $40.29 per Bbl of NGL (OPIS spot price). We then adjust these prices to reflect appropriate basis, quality, and location differentials over that period in estimating our proved reserves. During 2013, our monthly average realized natural gas prices, excluding the effect of derivative cash settlements, were as high as $4.41 per Mcf and as low as $3.45 per Mcf. For the same period, our monthly average realized crude oil prices before the effect of derivative cash settlements were as high as $97.87 per Bbl and as low as $83.14 per Bbl, and were as high as $39.36 per Bbl and as low as $31.20 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, some of which are 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.

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 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 expenditures of such properties. These limitations and our dependence on the operator and other working interest owners in 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 of a property or render it worthless, thus adversely affecting our financial condition, results of operations and operating cash flow if such property is of sufficient value.

Exploration and development drilling may not result in commercially producible reserves.
Crude oil and natural gas drilling, completion 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 adverse drilling or completion 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, tornadoes, flooding, or other adverse weather conditions;
- governmental permitting delays;
- 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 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, which could result in reduced or no production from the well, significant expenditure to repair the well, and/or the loss and abandonment of the well.

Results in our newer resource plays may be more uncertain than results in resource plays that are more developed and have longer established production histories. For example, industry experience and knowledge in the Eagle Ford shale play, is more limited compared to more established resource 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 newer resource plays than other areas with longer histories of development and production. Drilling and completion techniques that have proven to be successful in other resource plays are being used in the early development of these new plays; 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 for locations booked as proved undeveloped locations, or if we will be able to produce crude oil, natural gas, or NGLs from these 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 34 percent of our total net undeveloped acreage at December 31, 2013. 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 resource 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 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 production and ultimate recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore outside the desired drilling zone, deviating from 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, the inability to fracture stimulate the planned number of stages, the inability to run tools and other equipment the entire length of the well bore during completion operations, the inability 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.

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.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, that could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids towards the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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, we have entered into various derivative contracts. Our derivative contracts in place include swap and collar arrangements for crude oil, natural gas, and NGLs. As of December 31, 2013, we were in a net accrued asset position of $21.5 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. During 2013, we had three major customers, Regency Gas Services LLC, Anadarko, and Plains Marketing LP, which accounted for approximately 26 percent, 16 percent, and 12 percent, respectively, of our total production revenue. Please refer to Note 1 - Summary of Significant Accounting Policies, under the heading Concentration of Credit Risk and Major Customers in Part II, Item 8 of this report for further discussion of our concentration of credit risk and major customers. The loss of one or more of these customers could reduce competition for our products and negatively impact the prices of commodities we sell.

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, 2013, we were contractually committed to deliver 1,807 Bcf of natural gas and 53 MMBbl of oil pursuant to contracts expiring at various dates through 2023. We may enter into additional firm transportation agreements as our development of our resource plays expands. 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 those 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 properties and impairment of unproved properties totaling $172.6 million and $46.1 million, respectively, during 2013, $208.9 million and $16.3 million, respectively, during 2012, and $219.0 million and $7.4 million, respectively, during 2011. Significant declines in crude oil, natural gas, or NGL prices in the future or unsuccessful exploration efforts could cause additional proved and/or unproved property impairments in the future.

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.

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 $1.3 billion, subject to a borrowing base that the lenders redetermine semi-annually based 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 $2.2 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.

The amount of our 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, 2013, 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; $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; and $500.0 million of long-term senior unsecured debt outstanding relating to our 5.0% Senior Notes due 2024 (the "2024 Notes") that we issued on May 20, 2013 (collectively, the 2019 Notes, the 2021 Notes, the 2023 Notes, and the 2024 Notes are referred to as our "Senior Notes"); and no 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 borrowing under the facility on a dollar-for-dollar basis), resulting in $1,299.2 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, 2013.

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, 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, and/or restructure or refinance our debt. We might not be able to sell our equity, 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.

Our debt agreements, including the agreement governing our credit facility and the indentures governing the Senior 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 12-month trailing consolidated earnings before interest, taxes, depreciation, amortization, and exploration expense of less than 4.0, and (ii) maintenance of an adjusted current ratio of no less than 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 Senior 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.

We are subject to operating and environmental risks and hazards that could result in substantial losses or liabilities that may not be fully insured.

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 or tornadoes, freezing conditions, 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 outside 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 hazardous substances 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.

Following severe Atlantic hurricanes in recent years, the insurance markets suffered significant losses. As a result, insurance coverage for wind storms has been 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 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 and other federal agencies have asserted federal regulatory authority over certain aspects of hydraulic fracturing activities as outlined below.

The EPA has authority to regulate underground injections that contain diesel in the fluid system under the SDWA. The EPA has published draft guidance documents related to regulation of fracturing fluids using this regulatory authority. The EPA also plans to update its chloride water quality criteria for the protection of aquatic life under the Clean Water Act. Flowback and produced water from the hydraulic fracturing process contain total dissolved solids, including chlorides, and regulation of these fluids could be affected by the new criteria. The EPA has delayed issuing a draft criteria document until 2014. The EPA has also announced that it will develop pre-treatment standards for disposal of wastewater produced from shale gas operations through publicly owned treatment works. 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. If the EPA implements further regulations of hydraulic fracturing, 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 could even be prohibited from drilling and/or completing certain wells.

Certain states that we operate in, including 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 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. Recently, several municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries. For example, the city of Longmont, Colorado is currently in litigation with the State of Colorado to uphold the city’s ordinance that bans hydraulic fracturing. Similar events and processes are playing out in several cities, counties, and townships across the United States. 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 could even be prohibited from drilling and/or completing certain wells.

Several agencies of the federal governmental are actively involved in studies or reviews that focus on environmental aspects and impacts 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

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Representatives has conducted an investigation of hydraulic fracturing practices and government studies related thereto. 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. The EPA issued a progress report in 2012, and plans to issue a draft report of results in 2014 for public comment and independent peer review by the Science Advisory Board. The United States Department of Energy is actively involved in research on hydraulic fracturing practices, including groundwater protection. Also, the United States Department of the Interior proposed a rule to regulate hydraulic fracturing on public lands in May of 2013. The proposed rule contains disclosure requirements and other mandates for well integrity and management of water produced by the process, and will likely be finalized in 2014.

Legislation has been introduced before Congress, including 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, associated permitting delays, operational restrictions, litigation risk and potential cost increases. 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 SEC 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 also have ongoing research projects on hydraulic fracturing. These ongoing 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 the 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. These rules will require additional control equipment, changes to procedure, and extensive monitoring and reporting. The EPA stated in January 2013, however, that it intends to reconsider portions of the final rule. On September 23, 2013, the EPA published new standards for storage tanks subject to the NSPS. The EPA has stated that it continues to review other issues raised in petitions for reconsideration. 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. Over the past year, several court cases have addressed aspects of hydraulic fracturing. In a case that could delay operations on public lands, a court in California held that the BLM did not adequately consider the impact of hydraulic fracturing and horizontal drilling before issuing leases. Courts in New York and Colorado reduced the level of evidence required before a court will agree to consider alleged damage claims from hydraulic fracturing by property owners. Litigation resulting in financial compensation for damages linked to hydraulic fracturing could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to

increased regulation, permitting requirements, enforcement actions, and penalties. 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 new regulations, regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.
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 and others in our industry depend to complete wells that will produce commercial quantities of crude oil, natural gas, and associated liquids requires the use and disposal of significant quantities of water.
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 crude oil, natural gas, and natural gas liquids.
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.

Recent federal budget proposals, 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 potential changes include:

- the elimination of current deductions for intangible drilling and development costs;
- the repeal of the percentage depletion allowance for oil and natural gas properties;
- 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 made a finding that emissions of carbon dioxide, methane, and other "greenhouse gases" endanger public health and the environment because emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. Based on this "endangerment finding," the EPA has over the past four years adopted and implemented a comprehensive suite of regulations to restrict and otherwise regulate emissions of greenhouse gases under existing provisions of the CAA. In particular, the EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA. One rule requires a reduction in greenhouse gas emissions from motor vehicles, and the other regulates permitting and greenhouse gas emissions from certain large stationary sources. These EPA regulatory actions have been challenged by various industry groups, initially in the D.C. Circuit, which in 2012 ruled in favor of the EPA in all respects. However, the U.S. Supreme Court agreed to hear certain of industry's challenges to the EPA's application of the greenhouse gas endangerment finding to stationary sources, and a decision is expected in 2014. The EPA has also adopted reporting rules for greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries as well as certain onshore oil and natural gas production facilities.

Several other kinds of cases on greenhouse gases have been heard by the courts in recent years. While courts have generally declined to assign direct liability for climate change to large sources of greenhouse gas emissions, some have required increased scrutiny of such emissions by federal agencies and permitting authorities. There is a continuing risk of claims being filed against companies that have significant greenhouse gas emissions, and new claims for damages and increased government scrutiny will likely continue. Such cases often seek to challenge air emissions permits that greenhouse gas emitters apply for, seek to force emitters to reduce their emissions, or seek damages for alleged climate change impacts to the environment, people, and property. Any court rulings, laws or regulations that restrict or require reduced emissions of greenhouse gases could lead to increased operating and compliance costs, and could have an adverse effect on demand for the oil and natural gas that we produce.

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. Recently, the Congressional Budget Office provided Congress with a study on the potential effects on the U.S. economy of a tax on greenhouse gas emissions. While "carbon tax" legislation has been introduced in the Senate, the prospects for passage of such legislation are highly uncertain at this time.

On June 25, 2013, President Obama outlined plans to address climate change through a variety of executive actions, including reduction of methane emissions from oil and gas production and processing operations as well as pipelines and coal mines (the "Climate Plan"). The President's Climate Plan, along with recent regulatory initiatives and ongoing litigation filed by states and environmental groups, signal a new focus on methane emissions that could pose substantial regulatory risk to our operations. The Climate Plan could eventually result in:

•requirements for methane emission reductions from oil and gas equipment;

•increased scrutiny for sources emitting high levels of methane, including during permitting processes;

•analysis, regulation and reduction of methane emissions as a requirement for project approval;

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•agency adoption of regulations to reduce methane emissions from oil and gas production, processing, and pipelines, including emissions associated with equipment leaks, fugitives, flowback or waste;

•and actions taken by one agency for a specific industry establishing precedents for other agencies and industry sectors.

In relation to the Climate Plan, proposals to increase both the assumed "Global Warming Potential" ("GWP") and the assumed social costs associated with methane and other greenhouse gas emissions have been introduced. Changes to these measurement tools could adversely impact permitting requirements, application of agencies' existing regulations for source categories with high methane emissions, and determinations of whether a source qualifies for regulation under the CAA. These changes to how the impact of methane is measured and evaluated are still in process, and the potential outcome of the proposals remains uncertain.

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. Some scientists refute these predictions. However, President Obama's Climate Plan emphasizes preparation for such 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 events. 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. Federal regulations or policy changes regarding climate change preparation requirements could also impact our costs and planning requirements.

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. On November 5, 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. Comments on these new rules were due in early January 2014, and, as these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

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. Therefore, the Dodd-Frank Act and the rules promulgated thereunder could significantly increase the cost of derivative contracts (including through requirements to post collateral), 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 related 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 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 related 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. Any significant interruption in service from, damage to, or 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 and Bakken/Three Forks 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, 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, 2013, to February 12, 2014, the closing daily sale price of our common stock as reported by the New York Stock Exchange ranged from a low of $53.77 per share in January 2013 to a high of $91.98 per share in November 2013. 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.

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, which could adversely affect the price of our common stock.

Delaware corporate law and our certificate of incorporation and by-laws contain provisions that may have the effect of delaying or preventing a change of control of us or our management. 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. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our 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 12, 2014, 66,997,786 shares of our common stock were freely tradable without substantial restriction or the requirement of future registration under the Securities Act. Also as of that date, options to purchase 39,088 shares of our common stock were outstanding, all of which were exercisable. These options are exercisable at $20.87 per share. In addition, restricted stock units ("RSUs") providing for the issuance of up to a total of 574,188 shares of our common stock and 799,851 performance share units ("PSUs") were outstanding. 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 12, 2014, there were 67,056,441 shares of our common stock outstanding, which is net of 22,412 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 Senior 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.

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 filed a declaratory judgment action in Webb County, Texas, captioned SM Energy Company vs. W.H. Sutton, et al., seeking a judgment declaring a prior lease in the Eagle Ford shale play in South Texas had terminated with respect to 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 appealed the District Court's judgment to the Fourth Court of Appeals, which affirmed the District Court's judgment on November 13, 2013. This judgment became final on January 23, 2014.

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 continue to prosecute this action to recover any relief to which we are entitled.

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 district court did not rule on Chieftain's motion to certify the putative class, and stayed all proceedings until the United States Court of Appeals for the Tenth Circuit issued its rulings on class certification in two similar royalty class action lawsuits. On July 9, 2013, the Tenth Circuit issued its opinions, reversing the trial courts' grant of class certification and remanding the matters to the trial courts for those cases. The district court presiding over our case subsequently lifted its stay, and we expect Chieftain to file a new motion for class certification in the first half of 2015.

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, we are unable to estimate what impact, if any, the action will have on our financial condition, results of operations or cash flows. We are still evaluating the claims, but believe that we have properly paid royalties under Oklahoma law and have and will continue to vigorously defend this case. On December 30, 2013, we sold a substantial portion of our assets that were subject to this matter, and the buyer assumed any such liabilities related to such properties.

ITEM 4. MINE SAFETY DISCLOSURES

These disclosures are not applicable to us.

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 2013 and 2012, as reported by the New York Stock Exchange:

Quarter Ended	High	Low
December 31, 2013	$94.00	$76.72
September 30, 2013	$77.70	$60.22
June 30, 2013	$65.55	$55.30
March 31, 2013	$62.26	$52.67
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

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2008, and ending on December 31, 2013, 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 SEC.

Holders. As of February 12, 2014, the number of record holders of our common stock was 81. Based upon inquiry, management believes that the number of beneficial owners of our common stock is approximately 27,700.

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 2013. We expect that our practice of paying dividends on our common stock will continue, 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 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 $6.7 million in 2013 and $6.5 million in 2012.

Restricted Shares. We have no restricted shares outstanding as of December 31, 2013, 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, 2013, 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, 2013 - March 31, 2013	—	$—	—	3,072,184
April 1, 2013 - June 30, 2013	390	$59.84	—	3,072,184
July 1, 2013 - September 30, 2013	267,362	$60.50	—	3,072,184
October 1, 2013 - October 31, 2013	285	$77.19	—	3,072,184
November 1, 2013 - November 30, 2013	—	$—	—	3,072,184
December 1, 2013 - December 31, 2013	—	$—	—	3,072,184
Total October 1, 2013 - December 31, 2013	285	$77.19	—	3,072,184
Total	268,037	$60.51	—	3,072,184

(1) All shares purchased in 2013 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,				
	2013	2012	2011	2010	2009
	(in millions, except per share data)				
Total operating revenues	$2,293.4	$1,505.1	$1,603.3	$1,092.8	$832.2
Net income (loss)	$170.9	$(54.2)	$215.4	$196.8	$(99.4)
Net income (loss) per share:					
Basic	$2.57	$(0.83)	$3.38	$3.13	$(1.59)
Diluted	$2.51	$(0.83)	$3.19	$3.04	$(1.59)
Total assets at year-end	$4,705.2	$4,199.5	$3,799.0	$2,744.3	$2,360.9
Long-term debt:					
Revolving credit facility	$—	$340.0	$—	$48.0	$188.0
3.50% Senior Convertible Notes, net of debt discount	$—	$—	$285.1	$275.7	$266.9
Senior Notes	$1,600.0	$1,100.0	$700.0	$—	$—
Cash dividends declared and paid per common share	$0.10	$0.10	$0.10	$0.10	$0.10

Supplemental Selected Financial and Operations Data

	For the Years Ended December 31,				
	2013	2012	2011	2010	2009
Balance Sheet Data (in millions)					
Total working capital (deficit)	$8.4	$(201.0)	$(42.6)	$(227.4)	$(87.6)
Total stockholders' equity	$1,606.8	$1,414.5	$1,462.9	$1,218.5	$973.6
Weighted-average common shares outstanding (in thousands)					
Basic	66,615	65,138	63,755	62,969	62,457
Diluted	67,998	65,138	67,564	64,689	62,457
Reserves					
Oil (MMBbl)	126.6	92.2	71.7	57.4	53.8
Gas (Bcf)	1,189.3	833.4	664.0	640.0	449.5
NGLs (MMBbl)	103.9	62.3	27.5	—	—
MMBOE	428.7	293.4	209.9	164.1	128.7
Production and Operations (in millions)					
Oil, gas, and NGL production revenue	$2,199.6	$1,473.9	$1,332.4	$836.3	$616.0
Oil, gas, and NGL production expense	$597.0	$391.9	$290.1	$195.1	$206.8
Depletion, depreciation, amortization, and asset retirement obligation liability accretion expense	$822.9	$727.9	$511.1	$336.1	$304.2
General and administrative	$149.6	$119.8	$118.5	$106.7	$76.0
Production Volumes					
Oil (MMBbl)	13.9	10.4	8.1	6.4	6.3
Gas (Bcf)	149.3	120.0	100.3	71.9	71.1
NGLs (MMBbl)	9.5	6.1	3.5	—	—
MMBOE	48.3	36.5	28.3	18.3	18.2
Realized price					
Oil (per Bbl)	$91.19	$85.45	$88.23	$72.65	$54.40
Gas (per Mcf)	$3.93	$2.98	$4.32	$5.21	$3.82
NGL (per Bbl)	$35.95	$37.61	$53.32	$—	$—
Adjusted price (net of derivative cash settlements)					
Oil (per Bbl)	$89.92	$83.52	$78.89	$66.85	$56.74
Gas (per Mcf)	$4.14	$3.48	$4.80	$6.05	$5.59
NGL (per Bbl)	$36.66	$38.90	$47.90	$—	$—
Expense per BOE					
Lease operating expense	$4.82	$4.93	$5.30	$6.63	$8.00
Transportation	$5.34	$3.81	$3.05	$1.15	$1.14
Production taxes	$2.19	$2.00	$1.90	$2.86	$2.24
Depletion, depreciation, amortization, and asset retirement obligation liability accretion expense	$17.02	$19.95	$18.07	$18.33	$16.73
General and administrative	$3.09	$3.28	$4.19	$5.82	$4.18
Statement of Cash Flow Data (in millions)					
Provided by operating activities	$1,338.5	$922.0	$760.5	$497.1	$436.1
Used in investing activities	$(1,192.9)	$(1,457.3)	$(1,264.9)	$(361.6)	$(304.1)

Provided by (used in) financing activities	$130.7	$422.1	$618.5	$(141.1)	$(127.5)

Note: 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. 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 and 2009 NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the amounts.

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, oil-focused plays in the Permian Basin, and positions in emerging plays in East Texas and the Powder River Basin in Wyoming. 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 reserves growth. Furthermore, by entering these plays early, we believe we can capture larger resource potential at a lower cost. At year-end 2012, our reserves shifted from being majority gas to majority liquids. As a result, we now report equivalent volumes and per-unit metrics on a BOE basis rather than on an MCFE basis. Prior year volumes have been conformed to current year presentation.

Our principal business strategy is to focus on the early capture of resource plays in order to create and then enhance value for our stockholders 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 as appropriate, high-grade our portfolio 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.

In 2013, we had the following financial and operational results:

- At year-end 2013, we had estimated proved reserves of 428.7 MMBOE, of which 54 percent were liquids (oil and NGLs) and 49 percent were characterized as proved developed. We added 195.5 MMBOE 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 slight price revisions that increased our estimated proved reserves by 0.6 MMBOE. The prices used in the calculation of proved reserve estimates as of December 31, 2013 were $96.94 per Bbl, $3.67 per MMBtu, and $40.29 per Bbl, for oil, gas, and NGLs, respectively. These prices were two percent and 33 percent higher for oil and gas, respectively, and 12 percent lower for NGLs than the prices used at year-end 2012. We had upward engineering revisions of 7.2 MMBOE related primarily to Eagle Ford shale assets, offset partially by downward engineering revisions of certain legacy assets in our Permian region. Additionally, we removed 2.8 MMBOE of proved undeveloped gas reserves mainly in our South Texas & Gulf Coast region 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 acquisitions of 1.3 MMBOE and we divested of 18.2 MMBOE of proved reserves during the year, most of which related to the sale of our Anadarko Basin properties. We also divested of certain other assets in our Mid-Continent, Rocky Mountain, and Permian regions.

- The PV-10 value of our estimated proved reserves was $5.5 billion as of December 31, 2013, compared with $3.8 billion as of December 31, 2012. The after tax value, represented by the standardized measure calculation, was $4.0 billion as of December 31, 2013, compared with $3.0 billion as of December 31, 2012. 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 annual production in 2013. Our average daily production in 2013 was 38.2 MBbls of oil, 409.2 MMcf of gas, and 26.0 MBbls of NGLs, for an average daily equivalent production rate of 132.4 MBOE, compared with 99.7 MBOE in 2012, an increase of 33 percent year-over-year. Please refer to the caption Production Results below for additional discussion.
- We recorded net income of $170.9 million, or $2.51 per diluted share, for the year ended December 31, 2013. This compares with a net loss of $54.2 million, or a loss of $0.83 per diluted share, for the year ended December 31, 2012. Please refer to the caption Comparison of Financial Results and Trends Between 2013 and 2012 below for additional discussion regarding the components of net income (loss).
- We had record cash flow provided by operating activities of $1.3 billion for the year ended December 31, 2013, compared with $922.0 million for the year ended December 31, 2012, which was an increase of 45 percent year-over-year. Please refer to Analysis of cash flow changes between 2013 and 2012 below for additional discussion.
- We received net cash proceeds (net of marketing costs, Net Profits Plan payments, legal fees, and other selling costs paid) from the sale of oil and gas properties of $424.8 million for the year ended December 31, 2013. Please refer to Analysis of cash flow changes between 2013 and 2012 below for additional discussion.
- EBITDAX, a non-GAAP financial measure, for the year ended December 31, 2013, was $1.5 billion, compared with $1.0 billion for the same period in 2012. 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.
- Costs incurred for oil and gas producing activities for the year ended December 31, 2013, remained relatively flat at $1.7 billion when compared to the same period in 2012. Please refer to the caption Costs Incurred in Oil and Gas Producing Activities below for additional discussion.

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.

The following table provides various reserve replacement and finding and development cost metrics for the year ended December 31, 2013:

	Reserve Replacement Percentage				Finding and Development Cost per BOE (1)	
	Excluding Divestitures		Including Divestitures		Excluding Divestitures	Including Divestitures
Drilling, excluding revisions	405	%	367	%	$7.77	$8.56
Drilling, including revisions	415	%	377	%	$7.57	$8.33
Drilling and acquisitions, excluding revisions	407	%	370	%	$7.87	$8.67
Drilling and acquisitions, including revisions	418	%	380	%	$7.67	$8.43
All-in	418	%	380	%	$8.53	$9.37

(1) Please refer to Note 12 - Acquisition and Development 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, 2013:

	Reserve Replacement Percentage				Finding and Development Cost per BOE (1)	
	Excluding Divestitures		Including Divestitures		Excluding Divestitures	Including Divestitures
Drilling, excluding revisions	383	%	351	%	$10.58	$11.55
Drilling, including revisions	365	%	333	%	$11.11	$12.19
Drilling and acquisitions, excluding revisions	384	%	352	%	$10.62	$11.60
Drilling and acquisitions, including revisions	366	%	334	%	$11.15	$12.23
All-in	366	%	334	%	$11.98	$13.14

(1) Please refer to Note 12 - Acquisition and Development 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 percentages and finding and development costs are important analytical measures and 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 our oil, gas, and NGL production, which can fluctuate dramatically. We sell the majority of our 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 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 various industry posted prices, most commonly NYMEX WTI or Argus Louisiana Light Sweet (“Argus

LLS”). We are paid the average of the daily settlement price for the respective posted prices for the period in which the product is produced, adjusted for quality, transportation, API gravity, and location differentials. Substantially all of our oil production in our South Texas & Gulf Coast region is condensate. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period unless otherwise indicated.

The following table is a summary of commodity price data for the years ended December 31, 2013, 2012, and 2011:

	For the Years Ended December 31,		
	2013	2012	2011
Crude Oil (per Bbl):			
Average NYMEX price	$97.99	$94.10	$95.05
Realized price	$91.19	$85.45	$88.23
Natural Gas:			
Average NYMEX price (per MMBtu)	$3.73	$2.75	$4.00
Realized price (per Mcf)	$3.93	$2.98	$4.32
NGLs (per Bbl):			
Average OPIS price	$40.44	$44.91	$59.47
Realized price	$35.95	$37.61	$53.32

Note: 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 our actual product mix for NGL production. Actual prices received for NGLs produced reflect our actual product mix.

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 continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East. The relative strength of the U.S. dollar compared to other currencies could 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. If demand does not keep pace with anticipated growth in NGL supply, prices could be negatively impacted. The prices of several NGL products correlate to the price of oil and accordingly are likely to directionally follow that market. Gas prices have been under sustained downward pressure due to high levels of supply in recent years, although recent cold weather has provided a near term increase in pricing. Longer term, we think there remains a large amount of productive supply, particularly in the Northeast United States, which we anticipate will keep downward pressure on natural gas pricing. The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of December 31, 2013, and February 12, 2014:

	As of February 12, 2014	As of December 31, 2013
NYMEX WTI oil (per Bbl)	$96.31	$95.79
NYMEX Henry Hub gas (per MMBtu)	$4.64	$4.19
OPIS NGLs (per Bbl)	$40.49	$41.17

While 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. Our use of costless collars for a portion of our derivatives allows 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.

The following table presents our realized prices and the effects of derivative cash settlements for the years ended December 31, 2013, 2012, and 2011:

	For the Years Ended December 31,		
	2013	2012	2011
Crude Oil (per Bbl):			
Realized price	$91.19	$85.45	$88.23
Effects of derivative cash settlements	$(1.27)	$(1.93)	$(9.34)
Natural Gas (per Mcf):			
Realized price	$3.93	$2.98	$4.32
Effects of derivative cash settlements	$0.21	$0.50	$0.48
NGLs (per Bbl):			
Realized price	$35.95	$37.61	$53.32
Effects of derivative cash settlements	$0.71	$1.29	$(5.42)

The Dodd-Frank Act included provisions requiring over-the-counter derivative transactions to be cleared through clearinghouses and traded on exchanges. 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 that determine what types of transactions will be subject to regulation 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 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 entered into by entities predominantly engaged in non-financial activity 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.

2013 Highlights

Production Results. The table below provides a regional breakdown of our production for 2013:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total [1]
Production:					
Oil (MMBbl)	5.2	6.4	1.8	0.5	13.9
Gas (Bcf)	98.5	5.8	3.6	41.4	149.3
NGLs (MMBbl)	9.2	—	—	0.2	9.5
Equivalent (MMBOE) [1]	30.9	7.4	2.4	7.7	48.3
Avg. Daily Equivalents (MBOE/d)	84.7	20.3	6.5	21.0	132.4
Relative percentage	64 %	15 %	5 %	16 %	100 %

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

We had record production in 2013, which was primarily driven by the continued 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 2013 and 2012 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, 2013 (in millions)
Development costs	$ 1,350.1
Exploration costs	168.6
Acquisitions	
Proved properties	29.9
Unproved properties	172.5
Total, including asset retirement obligation	$ 1,721.1

The majority of costs incurred for oil and gas producing activities during 2013 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 2014.

Impairment of Proved Properties. We recorded impairment of proved properties expense of $172.6 million for the year ended December 31, 2013. The impairments in 2013 were a result of negative engineering revisions on Mississippian limestone assets in our Permian region at the end of the year, a plugging and abandonment program of our Olmos interval, dry gas assets in our South Texas & Gulf Coast region, and our decision to no longer pursue the development of certain under-performing assets during the year.

Divestiture Activity. During 2013, we received $445.8 million in total divestiture proceeds from divestitures of non-strategic properties, with the sale of our Anadarko Basin assets in December 2013 being the most significant transaction. Please refer to Note 3 - Divestitures and Assets Held for Sale in Part II, Item 8 of this report for additional discussion.

2024 Notes. During 2013, we issued $500.0 million in aggregate principal amount of 5.0% Senior Notes. The notes were issued at par and mature on January 15, 2024. We received net proceeds of $490.2 million from this issuance, which we used to reduce 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.

Revolving Credit Facility. On April 12, 2013, we and our lenders entered into a Fifth Amended and Restated Credit Agreement. The credit facility has aggregate lender commitments of $1.3 billion and a maturity date of April 12, 2018. Please refer to Overview of Liquidity and Capital Resources below for additional discussion of our credit facility.

Operational Activities. The primary focus of our operated drilling activity this year was oil and NGL-rich gas projects, with the majority of our 2013 capital budget being deployed to our Eagle Ford, Bakken/Three Forks and Permian development programs. We also participated in outside operated drilling activities primarily in oil and NGL-rich plays.

In our Eagle Ford shale program in South Texas, we operated five drilling rigs for the first half of the year. At midyear, we reduced our rig count by one due to gains in efficiencies through pad drilling, which allowed us to complete more wells per drilling rig. Our 2013 drilling program focused largely on multi-well pad drilling on the northern portions of our acreage position, which have higher condensate and NGL yields.

In our outside operated Eagle Ford shale program, the operator ran nine drilling rigs throughout 2013, adding a tenth rig near the end of the year. The majority of our non-operated Eagle Ford drilling and completion costs were funded by Mitsui during 2013 under the terms of our previously announced Acquisition and Development Agreement.

In our Bakken/Three Forks program in the North Dakota portion of the Williston Basin, we started the year with four operated rigs. At midyear, we released two of our traditional rigs and contracted a higher efficiency walking rig. Our 2013 drilling program was focused on infill drilling of our Gooseneck and Raven/Bear Den prospects by utilizing multi-well pads to further optimize our program.

In the second quarter of 2013, we closed our acquisition of approximately 40,000 net acres in the Powder River Basin, and in the third quarter we acquired an additional 33,000 net acres through a trade of non-core Northern DJ Basin assets, bringing our total year-end acreage in the Powder River Basin to approximately 140,000 net acres. We dedicated one rig to the Powder River Basin in the fourth quarter of 2013, which focused on delineation of the Frontier formation.

During 2013, we operated between two and three drilling rigs in our Permian region. In the first half of the year, we focused on three areas: development of the Bone Spring formation in southeast New Mexico, delineation of the Mississippian limestone formation, and testing of various shale targets, including the Wolfcamp shale in the Midland Basin. As we moved into the second half of the year, our focus transitioned to primarily testing the Wolfcamp B interval on our Sweetie Peck acreage in the Midland Basin. During 2013, we acquired additional acreage in the Permian Basin bringing our total to approximately 130,000 net acres at year-end.

In December 2013, we closed the sale of our Mid-Continent region Anadarko Basin assets, which included our interests in the Granite Wash interval. Please see the Divestiture Activity section above for additional information.

Outlook for 2014

We enter 2014 with a planned capital program of approximately $1.9 billion, of which approximately $1.7 billion will be focused on drilling and completion activities. We expect that approximately 85 percent of our drilling budget will be spent on our Eagle Ford shale, Bakken/Three Forks, and Permian shale programs.

In 2014, we plan to invest approximately $650 million of drilling and completion capital in our operated Eagle Ford shale program. Throughout 2014, 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. During 2014, 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, we expect the balance of the carry amount to be exhausted in early 2014. We plan to invest approximately $250 million of un-carried drilling and completion capital in this program in 2014 based on our anticipation of increased drilling and completion activity from 2013.

We plan to deploy approximately $350 million of our capital budget in our Bakken/Three Forks program, 80 percent of which will be spent on operated properties. In 2014, we plan to operate three drilling rigs focusing on infill drilling of our Raven/Bear Den and Gooseneck prospects. During 2014, we plan to monitor results of various well design and down-spacing tests of both our operated and non-operated properties.

In our Permian program, we plan to deploy approximately $155 million of drilling and completion capital. We plan to operate two to three drilling rigs throughout 2014, focusing on horizontal testing and development of the Wolfcamp formation in our Sweetie Peck and Buffalo prospects.

Of the remaining $255 million of our drilling and completion capital planned for 2014, the majority will be deployed in our Powder River Basin and East Texas programs. We plan to operate two drilling rigs in the Powder River Basin targeting the Frontier formation. We plan to operate between one and three drilling rigs on our East Texas Eagle Ford shale and Woodbine acreage in 2014. The majority of this budgeted capital will be spent on our operated properties.

Please refer to Overview of Liquidity and Capital Resources below for additional discussion regarding how we intend to fund our 2014 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, 2013, and the immediately preceding three quarters. Additional details of per BOE costs are presented later in this section.

	For the Three Months Ended			
	December 31, 2013	September 30, 2013	June 30, 2013	March 31, 2013
	(in millions, except for production data)			
Production (MMBOE)	13.2	12.8	12.0	10.3
Oil, gas, and NGL production revenue	$593.7	$601.8	$534.5	$469.6
Lease operating expense	$61.1	$61.0	$56.2	$54.7
Transportation costs	$75.0	$68.8	$67.0	$47.4
Production taxes	$26.7	$29.1	$26.5	$23.5
DD&A	$202.6	$195.8	$225.7	$198.7
Exploration	$21.8	$16.3	$20.7	$15.4
General and administrative	$48.0	$33.9	$35.4	$32.3
Net income	$7.0	$70.7	$76.5	$16.7

Selected Performance Metrics:

	For the Three Months Ended			
	December 31, 2013	September 30, 2013	June 30, 2013	March 31, 2013
Average net daily production equivalent (MBOE per day)	143.8	138.8	131.8	115.0
Lease operating expense (per BOE)	$4.62	$4.77	$4.69	$5.28
Transportation costs (per BOE)	$5.67	$5.38	$5.59	$4.58
Production taxes as a percent of oil, gas, and NGL production revenue	4.5 %	4.8 %	5.0 %	5.0 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion expense (per BOE)	$15.31	$15.33	$18.82	$19.20
General and administrative (per BOE)	$3.63	$2.66	$2.95	$3.12

Note: Amounts may not recalculate due to rounding.

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

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2013	2012	2011	2013/2012	2012/2011	2013/2012	2012/2011
Net production volumes [1]							
Oil (MMBbl)	13.9	10.4	8.1	3.6	2.3	34 %	28 %
Gas (Bcf)	149.3	120.0	100.3	29.3	19.7	24 %	20 %
NGLs (MMBbl)	9.5	6.1	3.5	3.4	2.6	55 %	75 %
Equivalent (MMBOE)	48.3	36.5	28.3	11.8	8.2	32 %	29 %
Average net daily production [1]							
Oil (MBbl per day)	38.2	28.3	22.1	9.9	6.2	35 %	28 %
Gas (MMcf per day)	409.2	328.0	274.8	81.2	53.1	25 %	19 %
NGLs (MBbl per day)	26.0	16.7	9.6	9.3	7.1	56 %	75 %
Equivalent (MBOE per day)	132.4	99.7	77.5	32.7	22.2	33 %	29 %
Oil, gas, and NGL production revenue (in millions)							
Oil production revenue	$1,271.5	$886.2	$712.8	$385.3	$173.4	43 %	24 %
Gas production revenue	586.3	357.7	433.4	228.6	(75.7)	64 %	(17)%
NGL production revenue	341.8	230.0	186.2	111.8	43.8	49 %	24 %
Total	$2,199.6	$1,473.9	$1,332.4	$725.7	$141.5	49 %	11 %
Oil, gas, and NGL production expense (in millions)							
Lease operating expenses	$233.0	$180.1	$149.8	$52.9	$30.3	29 %	20 %
Transportation costs	258.2	138.9	86.4	119.3	52.5	86 %	61 %
Production taxes	105.8	72.9	53.9	32.9	19.0	45 %	35 %
Total	$597.0	$391.9	$290.1	$205.1	$101.8	52 %	35 %
Realized price							
Oil (per Bbl)	$91.19	$85.45	$88.23	$5.74	$(2.78)	7 %	(3)%
Gas (per Mcf)	$3.93	$2.98	$4.32	$0.95	$(1.34)	32 %	(31)%
NGLs (per Bbl)	$35.95	$37.61	$53.32	$(1.66)	$(15.71)	(4)%	(29)%
Per BOE	$45.50	$40.39	$47.10	$5.11	$(6.71)	13 %	(14)%
Per BOE data							
Production costs:							
Lease operating expense	$4.82	$4.93	$5.30	$(0.11)	$(0.37)	(2)%	(7)%
Transportation costs	$5.34	$3.81	$3.05	$1.53	$0.76	40 %	25 %
Production taxes	$2.19	$2.00	$1.90	$0.19	$0.10	10 %	5 %
General and administrative	$3.09	$3.28	$4.19	$(0.19)	$(0.91)	(6)%	(22)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion expense	$17.02	$19.95	$18.07	$(2.93)	$1.88	(15)%	10 %
Derivative cash settlement [2]	$(0.42)	$(1.32)	$1.64	$0.90	$(2.96)	(68)%	(180)%
Earnings per share information							
Basic net income (loss) per common share	$2.57	$(0.83)	$3.38	$3.40	$(4.21)	410 %	(125)%
Diluted net income (loss) per common share	$2.51	$(0.83)	$3.19	$3.34	$(4.02)	402 %	(126)%
	66,615	65,138	63,755	1,477	1,383	2 %	2 %

Basic weighted-average common shares outstanding (in thousands)							
Diluted weighted-average common shares outstanding (in thousands)	67,998	65,138	67,564	2,860	(2,426)	4 %	(4)%

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(1) Amounts and percentage changes may not recalculate due to rounding.
(2) Derivative cash settlements are included within the realized hedge gain (loss) and derivative gain line items in the accompanying statements of operations.
We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average daily production for the year ended December 31, 2013, increased 33 percent compared to the same period in 2012, driven by continued development of our Eagle Ford shale assets.
Changes in production volumes, revenues, and costs reflect the highly volatile nature of our industry. Our realized price on a per BOE basis for the year ended December 31, 2013, increased 13 percent compared to the same period in 2012 due to improved oil and gas prices.
Lease operating expenses ("LOE") on a per BOE basis for the year ended December 31, 2013, decreased two percent compared to the same period in 2012. Overall, LOE costs increased; however, production increased at a faster rate, thereby reducing LOE on a per BOE basis. We expect LOE on a per BOE basis to increase in 2014 due to an increase in ad valorem taxes primarily in our Eagle Ford shale program.

Transportation costs on a per BOE basis for the year ended December 31, 2013, increased 40 percent compared to the same period in 2012. Our Eagle Ford shale program has meaningfully higher transportation expense per unit of production compared to our other regions. Ongoing development of the Eagle Ford shale program has resulted in these assets becoming a larger portion of our total production, thereby increasing company-wide transportation expense per BOE over time. The run-rate of our per unit transportation cost in the Eagle Ford shale program increased throughout 2013 due to incremental compression charges and increased variable fuel costs associated with higher natural gas prices. Additionally, our transportation arrangements have changed over the years presented to contracts that have more favorable terms for product prices but also include higher transportation fees. We anticipate we will recognize fluctuations in our per unit Eagle Ford shale transportation run-rate over time. In 2014, we expect transportation costs per BOE to increase as Eagle Ford shale production continues to grow and constitutes a larger portion of our production mix.

Production taxes on a per BOE basis for the year ended December 31, 2013, increased 10 percent compared to the same period in 2012. This increase is a result of State of Oklahoma incentive tax rebates recorded in 2012, which decreased the 2012 BOE rate. Additionally, we received smaller incentive tax rebates on newer wells drilled in our South Texas & Gulf Coast region in 2013. We generally expect production tax expense to trend with oil, gas, and NGL revenues, however, we expect production tax expense as a percentage of revenues to slightly increase as a result of lower production tax incentives.

General and administrative expense on a per BOE basis for the year ended December 31, 2013, decreased six percent compared to the same period in 2012, 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 correlate with net cash flows and therefore are subject to variability. In 2014, we expect general and administrative expense on a per BOE basis will decrease, as we anticipate production will continue to increase at a faster rate than our increase in absolute general and administrative expense.
Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense, for the year ended December 31, 2013, decreased 15 percent, on a per BOE basis, compared to the same period in 2012. Our DD&A rate can fluctuate as a result of impairments, divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Our DD&A rate has fallen largely as a result of lower finding and development costs, as well as through the utilization of our carry arrangement with Mitsui, which has allowed us to add reserves without incurring capital costs. Please refer to Note 12 - Acquisition and Development

Agreement in Part II, Item 8 of this report for additional discussion on the Mitsui transaction. Additionally, we closed our Anadarko Basin divestiture at the end of 2013. These assets were classified as held for sale at the beginning of the third quarter, and therefore, not depleted for substantially all of the last half of 2013. We expect DD&A on a per BOE basis to be lower in 2014 due to lower anticipated finding and development costs and the sale of our Anadarko Basin assets at the end of 2013. These impacts will be slightly offset as we begin paying our portion of capital on our outside operated Eagle Ford assets as a result of our remaining carry amount with Mitsui being exhausted in early 2014.

Please refer to Comparison of Financial Results and Trends between 2013 and 2012 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. 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 ended December 31, 2012, resulting in an increase in the diluted weighted-average common shares outstanding between the two periods.

Comparison of Financial Results and Trends between 2013 and 2012

Oil, gas, and NGL production. The following table presents the regional changes in our production and oil, gas, and NGL production revenues and production costs between the years ended December 31, 2013, and 2012:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas & NGL Revenue Added (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	33.4	$515.5	$159.2
Rocky Mountain	3.4	136.6	28.7
Permian	1.4	51.6	19.4
Mid-Continent	(5.5)	22.0	(2.2)
Total	32.7	$725.7	$205.1

The largest regional production increase occurred in our 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 continue to do so through 2014. The increase in oil and gas prices caused an increase in oil, gas, and NGL production revenue in our Mid-Continent region between the years ended December 31, 2013, and 2012, despite a decrease in production volumes attributable to base decline.

The following table summarizes the realized prices we received in 2013 and 2012, before the effects of derivative cash settlements:

	For the Years Ended December 31,	
	2013	2012
Realized oil price ($/Bbl)	$91.19	$85.45
Realized gas price ($/Mcf)	$3.93	$2.98
Realized NGL price ($/Bbl)	$35.95	$37.61
Realized equivalent price ($/BOE)	$45.50	$40.39

A 32 percent increase in production on an equivalent basis combined with a 13 percent increase in realized price per BOE resulted in a 49 percent increase in revenue between the two periods. Based on current levels of drilling and completion activity, we expect production volumes to continue to increase through 2014 on a retained properties basis. We also expect our realized prices to trend with commodity prices.

Realized hedge (loss) gain. We recorded a net realized hedge loss of $1.8 million for the year ended December 31, 2013, compared with a net realized hedge gain of $3.9 million for the same period in 2012. 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”). During 2013, all gains and losses associated with commodity derivative contracts that had previously been designated as cash flow hedges were reclassified into earnings from 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 gain on divestiture activity of $28.0 million for the year ended December 31, 2013, compared with a net loss of $27.0 million for the comparable period of 2012. The net gain on divestiture activity for the year ended December 31, 2013, is largely due to gains recorded on the divestiture of certain assets in our Mid-Continent and Rocky Mountain regions slightly offset by a loss recorded on the divestiture of non-strategic assets in our Permian region. The net loss for the year ended December 31, 2012, was due to an unsuccessful property sale effort and the corresponding write-down of those assets held for sale to their fair value. This loss was partially offset by a net gain on completed divestitures. We will continue to evaluate our portfolio to determine whether there are non-strategic properties we could divest. Please refer to Note 3 - Divestitures and 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 increased to $60.0 million for the year ended December 31, 2013, compared with $52.8 million for the comparable period of 2012, as a result of an increase in gas prices. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased to $57.6 million for the year ended December 31, 2013, from $47.6 million for the comparable period of 2012. The decrease in our net margin is due to an increase in gathering fees paid to third parties, which went into effect in the second half of 2012. We expect that marketed gas system revenue and expense will decrease in 2014 as a result of our Anadarko Basin divestiture, although we expect our margin to be consistent with the margin realized in 2013. Further, we expect marketed gas revenue and expense to continue to correlate with changes in production on retained properties and our realized gas price.

Oil, gas, and NGL production expense. Total production costs increased $205.1 million, or 52 percent, to $597.0 million for the year ended December 31, 2013, compared with $391.9 million in 2012, primarily due to a 32 percent increase in production volumes on a per BOE basis, as well as an overall increase in transportation costs in our South Texas & Gulf Coast region. 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 BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased 13 percent to $822.9 million in 2013 compared with $727.9 million in 2012, as a result of the continued development of our Eagle Ford and Bakken/Three Forks assets and the associated growth in our production, partially offset by the sale of our Anadarko Basin properties that were classified as held for sale at the beginning of the third quarter of 2013. 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 BOE basis.

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

	For the Years Ended December 31,	
	2013	2012
Summary of Exploration Expense	(in millions)	
Geological and geophysical expenses	$4.3	$13.6
Exploratory dry hole	5.8	20.9
Overhead and other expenses	64.0	55.7
Total	$74.1	$90.2

Exploration expense for 2013 decreased 18 percent compared with the same period in 2012 as a result of decreased geological and geophysical expenses (“G&G”) due to a large seismic study conducted in the first quarter of 2012 and fewer exploratory dry holes expensed in 2013, partially offset by an increase in exploration overhead in 2013 mainly due to an increase in performance-based compensation. 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. We currently expect to expand our exploration program in 2014, which will create increased potential for exploratory dry holes.

Impairment of proved properties. We recorded impairment of proved properties expense of $172.6 million for the year ended December 31, 2013. The impairments in 2013 were a result of negative engineering revisions on our Mississippian limestone assets in our Permian region at the end of the year, the commencement of a plugging and abandonment program of dry gas assets in the Olmos interval in our South Texas & Gulf Coast region, and our decision to no longer pursue the development of certain under-performing assets during the year. We recorded impairment of proved properties expense of $208.9 million for the comparable period in 2012 related to 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. Future crude oil, natural gas, and NGL price declines, downward engineering revisions, or unsuccessful exploration efforts may result in proved property impairments.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $46.1 million for the year ended December 31, 2013, the majority of which related to acreage we no longer intend to develop in our Permian region. We recorded $16.3 million of abandonment and impairment of unproved properties expense for the comparable period in 2012, the majority of which related to acreage we no longer intended to develop in our Rocky Mountain and Mid-Continent regions. Abandonment and impairment of unproved properties is 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 to $149.6 million for the year ended December 31, 2013, compared with $119.8 million for the same period in 2012. The increase is due to an increase in performance-based compensation that reflects we exceeded our performance metrics when compared to the prior year, as well as an increase in employee headcount during 2013, which resulted in increased base compensation, benefits, and general corporate office expenses. These were slightly offset by an increase in COPAS overhead reimbursement as a result of an increase in operated well count. 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 BOE 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 2013, we recorded a non-cash benefit of $21.8 million compared to a non-cash benefit of $28.9 million in 2012. 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. We expect the change in our Net Profits Plan liability to correlate with fluctuations in commodity prices.

Derivative gain. We recognized a derivative gain of $3.1 million for the year ended December 31, 2013, and a gain of $55.6 million for the same period in 2012. These amounts include the change in fair value of commodity derivative contracts and cash settlement gains or losses. For the year ended December 31, 2013, we recognized a net gain on cash settlements, which was offset largely by a decrease in the fair value of our gas commodity derivative contracts as strip prices increased. 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 $30.1 million in 2013 compared with $7.0 million in 2012. In 2013, other operating expense included $23.1 million of expense related to an agreed clarification concerning royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage.

Income tax benefit (expense). We recorded income tax expense of $107.7 million for 2013 compared to income tax benefit of $29.3 million for 2012, resulting in effective tax rates of 38.6 percent and 35.0 percent, respectively. The 2013 rate increase resulted primarily from the Anadarko Basin divestiture that closed at the end of the year, which caused a shift in anticipated recognition of future state tax benefits from a state with a higher applicable state rate to states with lower applicable rates. A combination of lower enacted state income tax rates during the year and a shift between states of our anticipated future apportioned income caused a decrease in our overall state rate which partially offset the increase. Other factors impacting our effective tax rate between tax years include decreased impact for valuation allowances, a decreased impact in benefit from the research and development (“R&D”) credit, and to a much lesser extent, net decreases resulting from the differing effects of percentage depletion and other permanent differences. Our current income tax expense in 2013 was $2.1 million compared with $370,000 in 2012, which is attributable to increasing activity in the state of Texas and effects of permanent differences associated with the Texas Margin Tax.

Although federal legislation was passed extending the R&D credit for the tax years 2012 and 2013, we are awaiting the outcome of our IRS appeal for R&D credits claimed during the 2007 through 2010 tax years to determine whether we can efficiently commit the additional resources necessary for engaging a study to calculate a credit for those and future years. As of the filing date of this report, the R&D credit has not been extended for the 2014 tax year. Even without recording the cumulative effect of a R&D credit in 2014, we anticipate our normalized tax rate will be lower in 2014.

Comparison of Financial Results between 2012 and 2011

Effective January 1, 2012, we combined our former ArkLaTex region with our Mid-Continent region, based in Tulsa, Oklahoma, for operational and reporting purposes.

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

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas & NGL Revenue Added (Lost) (in millions)	Production Costs Increase (in millions)
South Texas & Gulf Coast	19.5	$137.0	$68.9
Rocky Mountain	4.6	113.1	26.1
Permian	(0.1)	(16.5)	4.5
Mid-Continent	(1.8)	(92.1)	2.3
Total	22.2	$141.5	$101.8

The largest regional production increase occurred in our South Texas & Gulf Coast region as a result of drilling activity in our Eagle Ford shale program. 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 average 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	$53.32
Realized equivalent price ($/BOE)	$40.39	$47.10

A 29 percent increase in production on an equivalent basis combined with a 14 percent decrease in realized price per BOE resulted in an 11 percent increase in revenue between the two periods.

Realized hedge (loss) gain. 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. Please refer to Comparison of Financial Results and Trends between 2013 and 2012 above for additional discussion on this financial statement line item.

Gain (loss) on divestiture activity. We recorded a net loss on divestiture activity of $27.0 million for the year ended December 31, 2012, due largely to a loss on unsuccessful property sale efforts and the write-down of certain assets held for sale to their fair value. We recorded a net gain of $220.7 million for the comparable period of 2011, related to the divestitures of oil and gas properties located in our South Texas & Gulf Coast, Rocky Mountain, and Mid-Continent regions.

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.

Oil and gas 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.

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.

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 G&G expenses. The increase in G&G expenses was due to a large seismic study conducted in the first quarter of 2012, while the increase in overhead and other expenses was due to an increase in our exploration efforts.

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.

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.

Change in Net Profits Plan liability. For 2012, we recorded a non-cash benefit of $28.9 million compared to a non-cash benefit of $25.5 million in 2011. These non-cash benefits are 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 the Net Profits Plan liability in 2011.

Derivative gain. We recognized a 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. 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. 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, 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 differences in the effects of individual components of our tax rate between years. 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 R&D 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.

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 service commitments in order to provide flexibility to reduce activity and capital expenditures in periods of prolonged commodity price decline.

Sources of cash

We currently expect our 2014 capital program to be funded by cash flows from operations and proceeds from divestitures that closed during the fourth quarter of 2013, with any shortfall to be funded by borrowings under our credit facility. Although we anticipate that cash flows from these sources will be sufficient to fund our expected 2014 capital program, we may also elect to access the capital markets, depending on prevailing market conditions. The divestiture of 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 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. Historically, decreases in commodity prices have limited our industry's access to capital markets. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. See Credit Facility below for a discussion of the amendment and extension to our credit facility during the second quarter of 2013.

In the second quarter of 2013, we issued $500.0 million in aggregate principal amount of 2024 Notes and used the net proceeds to reduce outstanding amounts under our credit facility. 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, $573.8 million had been spent as of December 31, 2013. The remaining carry is expected to be realized in early 2014. Please refer to Note 12 - Acquisition and Development Agreement in Part II, Item 8 of this report for additional discussion.

Proposals for reform of the United States Internal Revenue Code and discussions regarding funding the federal government budget include eliminating or reducing current tax deductions for intangible drilling costs, depreciation of equipment acquisition costs, the domestic production activities deduction, and percentage depletion. Legislation modifying or eliminating these deductions would be expected to reduce net operating cash flows over time, 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

During the second quarter of 2013, we and our lenders entered into our Fifth Amended and Restated Credit Agreement, which replaced our previous credit facility. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The borrowing base under the credit facility as of the filing date of this report is $2.2 billion and is subject to regular semi-annual re-determinations. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility. Please refer to Note 5 - Long-term Debt in Part II, Item 8 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of February 12, 2014, December 31, 2013, and December 31, 2012.

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 by our credit agreement as the ratio of debt to 12-month trailing EBITDAX, of less than 4.0 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. Please refer to the caption Non-GAAP Financial Measures below for our definition of EBITDAX. As of December 31, 2013, our debt to EBITDAX ratio and adjusted current ratio were 1.1 and 3.1, respectively. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Our daily weighted-average credit facility debt balance was approximately $192.4 million and $171.8 million for the years ended December 31, 2013, and 2012, respectively. We used the proceeds from our 2024 Notes to reduce our credit facility balance at the end of the second quarter of 2013. Our average credit facility balance was lower throughout 2012 as a result of the use of proceeds from our 2021 Notes, issued at the end of 2011, and our 2023 Notes, issued at the end of the second quarter of 2012, to pay down our credit facility balance. Cash flows provided by our operating activities, proceeds received from divestitures of properties, and the amount of our capital expenditures also impact the amount we have borrowed under our credit facility.

Weighted-average interest rates

Our weighted-average interest rates include both paid and accrued interest payments, cash fees on the unused portion of the credit facility’s aggregate commitment amount, letter of credit fees, and amortization of deferred financing costs. Additionally, our 2012 weighted-average interest rate includes amortization of the debt discount related to our 3.50% Senior Convertible Notes due 2027 (the “3.50% Senior Convertible Notes”). Our weighted-average borrowing rate is calculated using only our paid and accrued interest.

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The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the years ended December 31, 2013, 2012, and 2011.

	For the Years Ended December 31,		
	2013	2012	2011
Weighted-average interest rate	6.3 %	6.4 %	8.5 %
Weighted-average borrowing rate	5.7 %	5.5 %	5.2 %

Our weighted-average interest rates and weighted average borrowing rates for the years ended December 31, 2013, 2012, and 2011, have been impacted by the issuance of the 2019 Notes in the first quarter of 2011, the issuance of the 2021 Notes in the fourth quarter of 2011, the settlement of our 3.50% Senior Convertible Notes in the second quarter of 2012, the issuance of the 2023 Notes in the second quarter of 2012, and the issuance of the 2024 Notes in the second quarter of 2013. Each of these events impacted the average balance on our revolving credit facility, the average interest rate on our non-bank debt, as well as the fees paid on the unused portion of our aggregate commitment.

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 2013, we spent $1.6 billion for exploration and development capital activities and proved and unproved oil and gas property acquisitions. 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 flows 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 periodically review our capital expenditure budget to assess changes in current and projected cash flows, 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, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, 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 2013, we did not repurchase any shares of our common stock, and we currently do not plan to repurchase any outstanding shares.

During 2013, we paid $6.7 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.

The following table presents changes in cash flows between the years ended December 31, 2013, 2012, and 2011, 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	
	2013	2012	2011	2013/2012	2012/2011	2013/2012	2012/2011
	(in millions)						
Net cash provided by operating activities	$1,338.5	$922.0	$760.5	$416.5	$161.5	45 %	21 %
Net cash used in investing activities	$(1,192.9)	$(1,457.3)	$(1,264.9)	$264.4	$(192.4)	(18)%	15 %
Net cash provided by financing activities	$130.7	$422.1	$618.5	$(291.4)	$(196.4)	(69)%	(32)%

Analysis of cash flow changes between 2013 and 2012

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $652.6 million, or 43 percent, to $2.2 billion for the year ended December 31, 2013, compared with the same period in 2012. This increase was due to an increase in production volumes and an increase in our adjusted realized price. Cash paid for lease operating expenses in 2013 increased $54.5 million from 2012 due to increased production. Cash paid for interest, net of capitalized interest, during 2013 increased $19.4 million compared with the same period in 2012 due to interest paid on our 2023 Notes in the first and third quarters of 2013, offset partially by interest no longer paid on the 3.50% Senior Convertible Notes that we settled in April 2012.

Investing activities. Net proceeds from the sale of oil and gas properties in 2013 increased $369.5 million compared to the same period in 2012 due largely to the sale of our Anadarko Basin assets in the fourth quarter of 2013. Capital expenditures in 2013, including costs to acquire proved and unproved oil and gas properties, increased $101.5 million, or seven percent, compared with the same period in 2012. This increase is primarily the result of our completed acquisition of proved and unproved properties in our Rocky Mountain region in the second quarter of 2013.

Financing activities. We received $490.2 million of net proceeds from the issuance of our 2024 Notes in 2013, compared with $392.1 million of net proceeds from the issuance of our 2023 Notes in 2012. These proceeds were used to reduce our outstanding credit facility balance. We had net payments under our credit facility of $340.0 million during the year ended December 31, 2013, compared with net borrowings of $340.0 million during the same period in 2012. During the second quarter of 2012, we paid $287.5 million to settle our 3.50% Senior Convertible Notes.

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, net of capitalized interest, during 2012

increased $29.2 million compared with the same period in 2011 due to interest payments on our 2019 Notes and 2021 Notes, as well as an increase in interest payments under our credit facility arising from an increase in our weighted average outstanding balance 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 during 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 their fair market values. As of December 31, 2013, our fixed-rate debt outstanding totaled $1.6 billion. As of December 31, 2013, we had no floating-rate debt outstanding, thus we had no exposure to market risk related to floating interest rates at that date.

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 NGL prices 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 2013 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 $127.1 million, $58.6 million, and $34.2 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, 2013, 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 millions)	
Gain/(loss):		
Oil derivatives	$(151.0)	$144.7
Gas derivatives	$(103.6)	$103.7
NGL derivatives	$(15.5)	$15.5

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.

Schedule of Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2013, 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)	$1,600.0	$—	$—	$—	$1,600.0
Interest payments (2)	843.9	105.7	203.6	200.1	334.5
Delivery commitments (3)	1,070.9	112.6	263.8	247.0	447.5
Operating leases and contracts (3)	142.7	66.5	27.8	14.0	34.4
Derivative liability (4)	31.0	26.4	4.5	0.1	—
Net Profits Plan (5)	59.4	14.3	21.5	16.8	6.8
Asset retirement obligations (6)	121.2	25.8	9.4	5.3	80.7
Other (7)	21.5	4.5	10.6	6.0	0.4
Total	$3,890.6	$355.8	$541.2	$489.3	$2,504.3

(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. No interest payments have been estimated on our credit facility due to its zero balance as of December 31, 2013. However, commitment fees paid on the unused portion of the aggregate commitment amount have been estimated through the credit facility maturity date of April 12, 2018, and included in the table above.

(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, 2013, 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, 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.

(6) Amount shown represents estimated future discounted abandonment costs. These obligations are recorded as liabilities on our accompanying balance sheet as of December 31, 2013. 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 relates to the unfunded portion of our estimated pension liability of $18.6 million, for which we have estimated the timing of future payments based on historical annual contribution amounts. We are expected to make contributions to the Pension Plan in 2014 of $4.3 million.

In addition to the amounts in the above table, we have committed to pay our portion of the development of infrastructure in our outside operated Eagle Ford shale program. The system owners unanimously approved budgeted capital expenditures for 2014, of which we are committed to pay approximately $33.0 million for the upcoming year.

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, 2013, 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. As of December 31, 2013, all variable interest entities have been consolidated.

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 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 each year-end. 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,		
	2013	2012	2011
	MMBOE Change	MMBOE Change	MMBOE Change
Revisions resulting from price changes	0.6	(12.1)	(4.2)
Revisions resulting from performance (1)	4.4	(15.3)	6.1
Total	5.0	(27.4)	1.9

(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 above under Overview of the Company.

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

	For the Years Ended December 31,					
	2013		2012		2011	
	MMBOE Change	Percentage Change	MMBOE Change	Percentage Change	MMBOE Change	Percentage Change
10% decrease in SEC pricing	(9.8)	(2)%	(11.2)	(4)%	(3.7)	(2)%
10% decrease in proved undeveloped reserves	(22.0)	(5)%	(12.7)	(4)%	(6.9)	(3)%

The table above solely reflects the impact of a 10 percent decrease 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 Information 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. Revenue is recognized when 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, local spot market, and OPIS 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 $23 million in 2013.

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. Prior to January 1, 2011, we designated our commodity derivative contracts as cash flow hedges, for which unrealized changes in fair value were recorded to AOCIL, to the extent the hedges were effective. As of January 1, 2011, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010. As a result, subsequent to December 31, 2010, we recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCIL. 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 change in our effective tax rate would have changed our calculated income tax expense by approximately $2.8 million for the year ended December 31, 2013.

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 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.

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 June 2013, President Obama announced a Climate Action Plan designed to further reduce greenhouse gas emissions and prepare the nation for the physical effects that may occur as a result of climate change. The Plan targets methane reductions from the oil and gas sector as part of a comprehensive interagency methane strategy. In addition, President Obama directed the EPA to issue stringent carbon standards for new fossil fuel-fired power plants. The EPA proposed new source performance standards in September 2013, which would require carbon capture and sequestration for coal-fired boilers and combined cycle technology for natural gas-fired boilers. The EPA has stated that it intends to propose greenhouse gas standards for existing fossil fuel-fired power plants by June 2014, finalize the standards by June 2015, and require plans by states to adopt the standards by 2016.

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, 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 federal regulation and 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 51 and 55 percent of our production on an BOE basis in 2013 and 2012, 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, derivative gains and losses net of cash settlements, 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 in nature 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 information to investors and analysts, 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 operating activities, or 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,		
	2013	2012	2011
	(in thousands)		
Net income (loss) (GAAP)	$170,935	$(54,249)	$215,416
Interest expense	89,711	63,720	45,849
Interest income	(67)	(220)	(466)
Income tax expense (benefit)	107,676	(29,268)	123,585
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	822,872	727,877	511,103
Exploration	65,888	81,809	46,776
Impairment of proved properties	172,641	208,923	219,037
Abandonment and impairment of unproved properties	46,105	16,342	7,367
Stock-based compensation expense (1)	32,347	30,185	26,824
Derivative gain	(3,080)	(55,630)	(37,086)
Derivative cash settlement gain (loss)	22,062	44,264	(25,671)
Change in Net Profits Plan liability	(21,842)	(28,904)	(25,477)
(Gain) loss on divestiture activity	(27,974)	27,018	(220,676)
EBITDAX (Non-GAAP)	1,477,274	1,031,867	886,581
Interest expense	(89,711)	(63,720)	(45,849)
Interest income	67	220	466
Income tax (expense) benefit	(107,676)	29,268	(123,585)
Exploration	(65,888)	(81,809)	(46,776)
Exploratory dry hole expense	5,846	20,861	277
Amortization of debt discount and deferred financing costs	5,390	6,769	18,299
Deferred income taxes	105,555	(29,638)	123,789
Plugging and abandonment	(9,946)	(2,856)	(5,849)
Other	2,775	527	(6,027)
Changes in current assets and liabilities	14,828	10,480	(40,794)
Net cash provided by operating activities (GAAP)	$1,338,514	$921,969	$760,532

(1) 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 in Item 7 above, as well as under the section entitled Summary of Oil, Gas, and NGL Derivative Contracts in Place under Note 10 – Derivative Financial Instruments in Part II, Item 8 of this report and is incorporated herein by reference.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of SM Energy Company and subsidiaries

We have audited the accompanying consolidated balance sheet of SM Energy Company and subsidiaries as of December 31, 2013, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of SM Energy Company and subsidiaries at December 31, 2013, and the consolidated results of its operations and its cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), SM Energy Company's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 19, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Denver, Colorado
February 19, 2014

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

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

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

As disclosed in Notes 1 and 10 to the consolidated financial statements, the accompanying 2012 consolidated financial statements give retrospective effect to new disclosure requirements regarding information related to offsetting of derivative assets and liabilities.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 21, 2013

(February 19, 2014 as to the disclosures regarding offsetting of derivative assets and liabilities as of December 31, 2012 in Notes 1 and 10)

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

	December 31, 2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents	$282,248	$5,926
Accounts receivable (note 2)	318,371	254,805
Refundable income taxes	4,630	3,364
Prepaid expenses and other	9,944	30,017
Derivative asset	21,559	37,873
Deferred income taxes	10,749	8,579
Total current assets	647,501	340,564
Property and equipment (successful efforts method):		
Land	1,857	1,845
Proved oil and gas properties	5,637,462	5,401,684
Less - accumulated depletion, depreciation, and amortization	(2,583,698)	(2,376,170)
Unproved oil and gas properties	271,100	175,287
Wells in progress	279,654	273,928
Materials inventory, at lower of cost or market	15,950	13,444
Oil and gas properties held for sale, net of accumulated depletion, depreciation and amortization of $7,390 in 2013 and $20,676 in 2012	19,072	33,620
Other property and equipment, net of accumulated depreciation of $28,775 in 2013 and $22,442 in 2012	218,395	153,559
Total property and equipment, net	3,859,792	3,677,197
Noncurrent assets:		
Derivative asset	30,951	16,466
Restricted cash	96,713	86,773
Other noncurrent assets	70,208	78,529
Total other noncurrent assets	197,872	181,768
Total Assets	$4,705,165	$4,199,529
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 2)	$606,751	$525,627
Derivative liability	26,380	8,999
Other current liabilities	6,000	6,920
Total current liabilities	639,131	541,546
Noncurrent liabilities:		
Revolving credit facility	—	340,000
Senior Notes (note 5)	1,600,000	1,100,000
Asset retirement obligation	115,659	112,912
Asset retirement obligation associated with oil and gas properties held for sale	3,033	1,393
Net Profits Plan liability	56,985	78,827
Deferred income taxes	650,125	537,383

Derivative liability	4,640	6,645
Other noncurrent liabilities	28,771	66,357
Total noncurrent liabilities	2,459,213	2,243,517
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 67,078,853 shares in 2013 and 66,245,816 shares in 2012; outstanding, net of treasury shares: 67,056,441 shares in 2013 and 66,195,235 shares in 2012	671	662
Additional paid-in capital	257,720	233,642
Treasury stock, at cost: 22,412 shares in 2013 and 50,581 shares in 2012	(823)	(1,221)
Retained earnings	1,354,669	1,190,397
Accumulated other comprehensive loss	(5,416)	(9,014)
Total stockholders' equity	1,606,821	1,414,466
Total Liabilities and Stockholders' Equity	$4,705,165	$4,199,529

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

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

	For the Years Ended December 31, 2013	2012	2011
Operating revenues:			
Oil, gas, and NGL production revenue	$2,199,550	$1,473,868	$1,332,392
Realized hedge (loss) gain	(1,777)	3,866	(20,707)
Gain (loss) on divestiture activity	27,974	(27,018)	220,676
Marketed gas system revenue	60,039	52,808	69,898
Other operating revenues	7,588	1,578	1,059
Total operating revenues and other income	2,293,374	1,505,102	1,603,318
Operating expenses:			
Oil, gas, and NGL production expense	597,045	391,872	290,111
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	822,872	727,877	511,103
Exploration	74,104	90,248	53,537
Impairment of proved properties	172,641	208,923	219,037
Abandonment and impairment of unproved properties	46,105	16,342	7,367
General and administrative	149,551	119,815	118,526
Change in Net Profits Plan liability	(21,842)	(28,904)	(25,477)
Derivative gain	(3,080)	(55,630)	(37,086)
Marketed gas system expense	57,647	47,583	64,249
Other operating expenses	30,076	6,993	17,567
Total operating expenses	1,925,119	1,525,119	1,218,934
Income (loss) from operations	368,255	(20,017)	384,384
Nonoperating income (expense):			
Interest income	67	220	466
Interest expense	(89,711)	(63,720)	(45,849)
Income (loss) before income taxes	278,611	(83,517)	339,001
Income tax (expense) benefit	(107,676)	29,268	(123,585)
Net income (loss)	$170,935	$(54,249)	$215,416
Basic weighted-average common shares outstanding	66,615	65,138	63,755
Diluted weighted-average common shares outstanding	67,998	65,138	67,564
Basic net income (loss) per common share	$2.57	$(0.83)	$3.38
Diluted net income (loss) per common share	$2.51	$(0.83)	$3.19

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

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

	For the Years Ended December 31, 2013	2012	2011
Net income (loss)	$170,935	$(54,249)	$215,416
Other comprehensive income (loss), net of tax:			
Reclassification to earnings [(1)]	1,115	(2,264)	12,997
Pension liability adjustment [(2)]	2,483	(2,470)	(1,795)
Total other comprehensive income (loss), net of tax	3,598	(4,734)	11,202
Total comprehensive income (loss)	$174,533	$(58,983)	$226,618

[(1)] Reclassification from accumulated other comprehensive income related to de-designated hedges. Refer to Note 10 - Derivative Financial Instruments for further information.
[(2)] Pension amounts are reclassified to General and administrative expense on the Company's consolidated statements of operations. The net of tax effect of the reclassification was approximately $768,000 in 2013.

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, 2011	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 withholdings	278,773	3	(9,976)	—	—	—	—	(9,973)
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
Net income	—	—	—	—	—	170,935	—	170,935
Other comprehensive income	—	—	—	—	—	—	3,598	3,598
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,663)	—	(6,663)
Issuance of common stock under Employee Stock Purchase Plan	77,427	1	3,671	—	—	—	—	3,672
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	526,852	5	(16,225)	—	—	—	—	(16,220)
Issuance of common stock upon stock option exercises	228,758	3	3,183	—	—	—	—	3,186
Stock-based compensation expense	—	—	31,949	28,169	398	—	—	32,347
Other income tax benefit	—	—	1,500	—	—	—	—	1,500
Balances, December 31, 2013	67,078,853	$671	$257,720	(22,412)	$(823)	$1,354,669	$ (5,416)	$1,606,821

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

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

	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities:			
Net income (loss)	$170,935	$(54,249)	$215,416
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
(Gain) loss on divestiture activity	(27,974)	27,018	(220,676)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	822,872	727,877	511,103
Exploratory dry hole expense	5,846	20,861	277
Impairment of proved properties	172,641	208,923	219,037
Abandonment and impairment of unproved properties	46,105	16,342	7,367
Stock-based compensation expense	32,347	30,185	26,824
Change in Net Profits Plan liability	(21,842)	(28,904)	(25,477)
Derivative gain	(3,080)	(55,630)	(37,086)
Derivative cash settlement gain (loss)	22,062	44,264	(25,671)
Amortization of debt discount and deferred financing costs	5,390	6,769	18,299
Deferred income taxes	105,555	(29,638)	123,789
Plugging and abandonment	(9,946)	(2,856)	(5,849)
Other	2,775	527	(6,027)
Changes in current assets and liabilities:			
Accounts receivable	(78,494)	(21,389)	(41,998)
Refundable income taxes	(1,266)	2,217	2,901
Prepaid expenses and other	1,364	(1,484)	16,376
Accounts payable and accrued expenses	93,224	31,136	(18,073)
Net cash provided by operating activities	1,338,514	921,969	760,532
Cash flows from investing activities:			
Net proceeds from sale of oil and gas properties	424,849	55,375	364,522
Capital expenditures	(1,553,536)	(1,507,828)	(1,633,093)
Acquisition of proved and unproved oil and gas properties	(61,603)	(5,773)	—
Receipts from restricted cash related to 1031 exchange	(1,754)	—	—
Other	(859)	893	3,661
Net cash used in investing activities	(1,192,903)	(1,457,333)	(1,264,910)
Cash flows from financing activities:			
Proceeds from credit facility	1,203,000	1,609,000	322,000
Repayment of credit facility	(1,543,000)	(1,269,000)	(370,000)
Debt issuance costs related to credit facility	(3,444)	—	(8,719)
Net proceeds from Senior Notes	490,185	392,138	684,242
Repayment of 3.50% Senior Convertible Notes	—	(287,500)	—
Proceeds from sale of common stock	6,858	5,816	7,327
Dividends paid	(6,663)	(6,511)	(6,382)
Net share settlement from issuance of stock awards	(16,220)	(21,622)	(9,973)
Other	(5)	(225)	—
Net cash provided by financing activities	130,711	422,096	618,495

Net change in cash and cash equivalents	276,322	(113,268)	114,117
Cash and cash equivalents at beginning of period	5,926	119,194	5,077
Cash and cash equivalents at end of period	$282,248	$5,926	$119,194

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

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

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

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Cash paid for interest, net of capitalized interest	$(70,702)	$(51,328)	$(22,133)
Net cash refunded for income taxes	$204	$1,389	$4,046

As of December 31, 2013, 2012, and 2011, $217.8 million, $262.8 million, and $214.8 million, respectively, of accrued capital expenditures were included in accounts payable and accrued expenses in the Company's consolidated balance sheets. These oil and gas property additions are reflected in cash used in investing activities in the periods during which the payables are settled.

During the third quarter of 2013, the Company closed an exchange of properties in its Rocky Mountain region with a fair value of $25.0 million. The insignificant amount of cash consideration paid at closing for purchase price adjustments is reflected in the acquisition of proved and unproved oil and gas properties line item in the consolidated statements of cash flows.

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 crude oil and condensate, 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, 2013, through the filing date of this report. Certain prior period amounts have been reclassified to conform to the current period presentation on the accompanying balance sheets and accompanying consolidated statements of cash flows (“accompanying statements of cash flows”). The Company’s Senior Notes are combined and presented as a single line item within the accompanying balance sheets in the current year whereas they were individually presented in prior periods. The Company's total derivative gain is now presented on the accompanying statements of cash flows in cash flows from operating activities with an additional line item to adjust for the cash settlement portion.
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 expense, 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 mainly consists of cash payments that are contractually restricted to be used solely for development of long-term capital assets 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 for additional information.

Accounts Receivable

The Company's accounts receivable 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.

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, 2013 and 2012, 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 regular review. During 2013, the Company had three major customers, Regency Gas Services LLC, Anadarko, and Plains Marketing LP, which accounted for approximately 26 percent, 16 percent, and 12 percent, respectively, of total oil, gas, and NGL production revenue. During the third quarter of 2013, the Company entered into various marketing agreements with Anadarko whereby the Company is subject to certain gathering, transportation, and processing through-put commitments for up to 10 years pursuant to each contract. While Anadarko is the first purchaser under these contracts, the Company also shares the risk of non-performance by Anadarko's counterparty purchasers. Several of Anadarko's counterparty purchasers under these contracts are also direct purchasers of products produced by the Company. During 2012, the Company had two major customers, Regency Gas Services LLC and Plains Marketing LP, which accounted for approximately 21 percent and 13 percent, respectively, of total production revenue. During 2011, the Company had one major customer, Regency Gas Services LLC, which accounted for approximately 18 percent of 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. Three counterparties were downgraded during 2013, but all maintain investment grade ratings. Our lowest rated counterparty carries credit ratings of BBB- and Baa2, by Standard & Poor's and Moody's, respectively. Per the terms of our agreement with that counterparty, 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; Houston, Texas; Midland, Texas; and Billings, Montana. The Company has accounts with a local bank in Tulsa, Oklahoma. As a result of the Anadarko Basin divestiture closing at the end of 2013, the Company had a large cash balance at December 31, 2013, which was invested in money market funds among various financial institutions. This is in line with 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 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, 2013, and 2012, the estimated salvage value of the Company's equipment was $57.5 million and $64.4 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 $16.0 million and $13.4 million at December 31, 2013, and 2012, respectively. There were no materials inventory write-downs for the years ended December 31, 2013, 2012, or 2011.

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, 2013, and 2012, the Company had $10.8 million of intangible assets consisting of acquired water rights, which are included as other noncurrent assets in the accompanying balance sheets. All intangible assets with indefinite lives are evaluated for impairment annually or if impairment indicators arise.

Internal-Use Software Development Costs

The Company capitalizes certain software costs incurred during the application development stage. The application development stage generally includes software design, configuration, testing and installation activities. Training and maintenance costs are expensed as incurred, while upgrades and enhancements are capitalized if it is probable that such expenditures will result in additional functionality. Capitalized software costs are depreciated over the estimated useful life of the underlying project on a straight-line basis upon completion of the project. As of December 31, 2013, the Company has capitalized approximately $11.2 million related to the ongoing development and implementation of accounting and operational software.

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 or Argus LLS 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.

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. Revenue is recognized when 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 knowledge of its properties and historical performance, NYMEX, OPIS, and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates.

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.

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 that management believes are 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 $172.6 million, $208.9 million, and $219.0 million, of proved property impairments for the years ended December 31, 2013, 2012, and 2011, respectively. The impairments in 2013 resulted from the write-down of certain Mississippian limestone assets in the Company's Permian region due to negative engineering revisions, write-downs related to Olmos interval, dry gas assets in the South Texas & Gulf Coast region as a result of a plugging and abandonment program, and write-downs of certain underperforming assets due to the Company's decision to no longer pursue the development of those assets. 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.

For the years ended December 31, 2013, 2012, and 2011, the Company recorded expense related to the abandonment and impairment of unproved properties of $46.1 million, $16.3 million, and $7.4 million, respectively. The Company's abandonment and impairment of unproved properties in 2013 was mostly related to acreage the Company no longer intends to develop in its Permian region. The Company's abandonment and impairment of unproved properties in 2012 related to acreage that the Company no longer intended to develop in its 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, 2013, 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 (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 diluted 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 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 and all subsequent years the shares remained outstanding. 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 year ended December 31, 2011, making the 3.50% Senior Convertible Notes dilutive for that period.
The treasury stock method is used to measure the dilutive impact of in-the-money stock options, unvested RSUs, contingent PSUs, and the 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,		
	2013	2012	2011
	(in thousands)		
Dilutive	1,383	—	3,809
Anti-dilutive	—	2,102	—

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

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands, except per share amounts)		
Net income (loss)	$170,935	$(54,249)	$215,416
Basic weighted-average common shares outstanding	66,615	65,138	63,755
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	1,383	—	2,592
Add: dilutive effect of 3.50% Senior Convertible Notes	—	—	1,217
Diluted weighted-average common shares outstanding	67,998	65,138	67,564
Basic net income (loss) per common share	$2.57	$(0.83)	$3.38
Diluted net income (loss) per common share	$2.51	$(0.83)	$3.19

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).

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

	Derivative Reclassification to Earnings	Pension Liability Adjustments
	(in thousands)	
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)
For the year ended December 31, 2013		
Before tax income	$1,777	$4,005
Tax expense	(662)	(1,522)
Income, net of tax	$1,115	$2,483

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 no borrowings outstanding under its credit facility as of December 31, 2013. The Company had $340.0 million of outstanding loans under its credit facility as of December 31, 2012. The Company’s Senior Notes are recorded at cost and the respective 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 within 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.

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. As of December 31, 2013, all variable interest entities have been consolidated.

Recently Issued Accounting Standards

On January 1, 2013, the Company adopted new authoritative accounting guidance issued by the Financial Accounting Standards Board (“FASB”), which enhanced disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position and provided clarification as to the specific instruments that should be considered in these disclosures. These pronouncements were issued to facilitate comparison between financial statements prepared on the basis of GAAP and International Financial Reporting Standards. These disclosures are effective for annual and interim reporting periods beginning on or after January 1, 2013, and are to be applied retrospectively for all comparative periods presented. The impact of retrospectively adopting these pronouncements did not have a material impact on the Company’s consolidated financial statements, but did impact the Company’s disclosures. See Note 10 - Derivative Financial Instruments for tabular presentation of the Company’s gross and net derivative positions.

On January 1, 2013, the Company adopted the presentation requirements of new authoritative accounting guidance issued by the FASB in February 2013. The purpose of the guidance was to improve the reporting of reclassifications out of accumulated other comprehensive income (loss) (“AOCIL”) by requiring entities to report the effect of significant reclassifications out of AOCIL into current year income within the respective line items in net income. The presentation of those amounts may be on the face of the financial statements or in the notes thereto. This amendment was effective prospectively for periods beginning after December 15, 2012, and the Company's financial statements and disclosures were not significantly impacted.

In February 2013, the FASB issued new authoritative accounting guidance related to the recognition and measurement of obligations arising from joint and several liability arrangements. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2013 and is to be applied retrospectively. Based on its evaluation, the Company determined this guidance does not currently impact the Company’s financial statements and disclosures.

In July 2013, the FASB issued new authoritative accounting guidance related to the reporting of unrecognized tax benefits when a net operating loss carryforward, similar tax loss, or tax credit carryforward exists. The guidance states an unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carry-forward, a similar tax loss, or a tax credit carry-forward, with certain exceptions. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2013, and is to be applied prospectively to all unrecognized tax benefits that exist at the effective date. The Company elected to early adopt this guidance in December 2013, which does not significantly affect the Company's financial statements and related disclosures.

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, 2013.

Note 2 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	As of December 31, 2013	2012
	(in thousands)	
Accrued oil, gas, and NGL production revenue	$228,169	$160,568
Amounts due from joint interest owners	37,517	42,740
Acquisition and Development Agreement receivable	—	19,931
State severance tax refunds	29,213	17,237
Other	23,472	14,329
Total accounts receivable	$318,371	$254,805

Accounts payable and accrued expenses are comprised of the following:

	As of December 31, 2013	2012
	(in thousands)	
Accrued capital expenditures	$217,820	$243,611
Revenue and severance tax payable	87,852	65,494
Accrued lease operating expense	29,296	28,037
Accrued property taxes	10,401	9,478
Joint owner advances	96,636	69,639
Accrued compensation	71,466	35,607
Accrued interest	40,027	25,027
Other	53,253	48,734
Total accounts payable and accrued expenses	$606,751	$525,627

Note 3 – Divestitures and Assets Held for Sale

2013 Divestiture Activity

- Mid-Continent Divestitures. In December 2013, the Company divested of certain non-strategic assets located in its Mid-Continent region, with the largest transaction being the sale of the Company’s Anadarko Basin assets. Total cash proceeds received at closing (referred throughout this report as “divestiture proceeds”) were $370.3 million. The estimated net gain on these divestitures is $29.2 million. These divestitures are subject to normal post-closing adjustments and are expected to be finalized during the first half of 2014. A portion of one 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”).

- Rocky Mountain Divestitures. During 2013, the Company divested of certain non-strategic assets located in its Rocky Mountain region. Total divestiture proceeds were $56.3 million. The estimated net gain on these divestitures is $10.1 million. These divestitures are subject to normal post-closing adjustments and are expected to be finalized during the first half of 2014.

- Permian Divestiture. In December 2013, the Company divested of certain non-strategic assets located in its Permian region. Total divestiture proceeds were $14.5 million. The estimated net loss on this divestiture is $6.5 million. This divestiture is subject to normal post-closing adjustments and is expected to be finalized during the first half of 2014.

The Company recorded an immaterial write-down to fair value less estimated costs to sale for assets that were held for sale as of December 31, 2013, which was reflected in the gain (loss) on divestiture activity line item in the accompanying statements of operations. See section Assets Held for Sale below for further discussion.

2012 Divestiture Activity

In 2012, the Company divested of various non-strategic properties located in its Rocky Mountain and Mid-Continent regions. Final divestiture proceeds, after the transactions post-closed in 2013, were $57.9 million and the final net gain on these divestitures was $7.4 million.

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.

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 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.

- 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.

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 costs 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, 2013, the accompanying balance sheets present $19.1 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense. A corresponding asset retirement obligation liability of $3.0 million is separately presented. The assets held for sale include the Company’s Marcellus shale assets located in Pennsylvania and other certain non-strategic assets in exploratory areas, 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.

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

Subsequent to December 31, 2013, the Company began marketing certain non-strategic assets in its Rocky Mountain region. The Company expects the closing of these asset sales will occur in the first half of 2014. These assets were not classified as held for sale as of December 31, 2013.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Current portion of income tax expense (benefit)			
Federal	$—	$—	$(1,757)
State	2,121	370	1,553
Deferred portion of income tax expense (benefit)	105,555	(29,638)	123,789
Total income tax expense (benefit)	$107,676	$(29,268)	$123,585
Effective tax rate	38.6%	35.0%	36.5%

The Company reduces its income tax payable to reflect employee stock option exercises. There was no excess income tax benefit associated with stock awards in 2013, 2012, or 2011.

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

	As of December 31, 2013	2012
	(in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$768,463	$678,624
Derivative asset	9,529	15,942
Other	1,245	6,443
Total deferred tax liabilities	779,237	701,009
Deferred tax assets:		
Federal and state tax net operating loss carryovers	91,788	113,522
Net Profits Plan liability	20,913	29,233
Stock compensation	18,820	18,026
Other long-term liabilities	13,341	16,739
Total deferred tax assets	144,862	177,520
Valuation allowance	(5,001)	(5,315)
Net deferred tax assets	139,861	172,205
Total net deferred tax liabilities	639,376	528,804
Less: current deferred income tax liabilities	(172)	(5,442)
Add: current deferred income tax assets	10,921	14,021
Non-current net deferred tax liabilities	$650,125	$537,383
Current federal income tax refundable	$4,630	$2,511
Current state income tax refundable	$—	$853
Current state income tax payable	$1,460	$—

At December 31, 2013, the Company estimated its federal net operating loss carryforward at $376.1 million, which includes unrecognized excess income tax benefits associated with stock awards of $126.7 million. The Company expects future excess benefit utilization to be recognized using the with-and-without method. The federal net operating loss carryforward begins to expire in 2031. The Company has estimated state net operating loss carryforwards of $147.5 million that expire between 2014 and 2034. The Company has federal research and development ("R&D") credit carryforwards of $5.0 million that expire between 2028 and 2031. 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. The change in the valuation allowance from 2012 to 2013 primarily reflects utilization of Oklahoma net operating losses resulting from the 2013 Anadarko Basin asset divestiture gain offset in part by a change in the Company's position regarding anticipated utilization of cumulative net operating losses attributed to other states.

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, changes in valuation allowances, percentage depletion, R&D credits, and other permanent differences, as follows:

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Federal statutory tax expense (benefit)	$97,514	$(29,231)	$118,652
Increase (decrease) in tax resulting from:			
State tax expense (benefit) (net of federal benefit)	9,400	(992)	6,458
Research and development credit	—	(970)	(4,516)
Change in valuation allowance	(314)	1,524	1,627
Statutory depletion	(154)	(210)	(341)
Other	1,230	611	1,705
Income tax expense (benefit)	$107,676	$(29,268)	$123,585

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. Significant divestiture activity impacting the Company's blended state rate occurred during the fourth quarter of 2013.

The Company and its subsidiaries file federal income tax returns and various state income tax returns. 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 2007. Federal tax law allowing for the calculation of an R&D credit was enacted in 2013, but the Company has not yet commissioned a study to calculate the credit for the 2012 or 2013 tax years. The table above excludes the impact for any credit that would be allowed under the new law in either period. The Internal Revenue Service ("IRS") initiated an audit in the first quarter of 2012 related to R&D tax credits claimed by the Company for the 2007 through 2010 tax years. On April 23, 2013, the IRS issued a Notice of Proposed Adjustment disallowing $4.6 million of R&D tax credits claimed for open tax years during the audit period. The Company maintains it is entitled to the claimed credits and was notified during December 2013 the case has been received by the IRS Appeals office, but a conference had not been scheduled as of the filing date of this report. In the fourth quarter of 2013, the Company filed a federal net operating loss carryback claim along with other audit adjustments not processed during the 2013 audit, amounting to a $4.0 million refund.

On September 13, 2013 the United States Department of the Treasury and IRS issued final and re-proposed tangible property regulations effective for tax years beginning January 1, 2014. The Company has determined it is materially compliant with the requirements of these regulations as of December 31, 2013.

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. At December 31, 2013, the Company estimates the range of reasonably possible change in 2014 to the table below could be from zero to $1.4 million.

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

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Beginning balance	$2,278	$1,961	$807
Additions based on tax positions related to current year	—	—	1,172
Additions for tax positions of prior years	80	317	183
Reductions for lapse of statute of limitations	—	—	(201)
Ending balance	$2,358	$2,278	$1,961

Note 5 – Long-term Debt

Revolving Credit Facility

The Company and its lenders entered into a Fifth Amended and Restated Credit Agreement on April 12, 2013, which replaced the Company's previous credit facility. The Company incurred approximately $3.4 million in deferred financing costs associated with the amendment and extension of this credit facility. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The initial borrowing base under the credit facility was $1.9 billion. On May 20, 2013, the Company's borrowing base under the credit facility was automatically reduced, by 25 percent of the aggregate principal amount of the newly-issued 2024 Notes, to $1.775 billion. The borrowing base is subject to regular semi-annual redeterminations. On September 6, 2013, the lending group redetermined the Company's borrowing base under the credit facility and increased it to $2.2 billion. The borrowing base redetermination process under the credit facility considers the value of the Company's oil and gas properties and other assets, as determined by the bank group. The next scheduled redetermination date is April 1, 2014. Borrowings under the facility are secured by a large majority of the Company's proved oil and gas properties.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to EBITDAX, as defined by our credit agreement as the ratio of debt to 12-month trailing EBITDAX, of less than 4.0 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. The Company was in compliance with all financial and non-financial covenants under the credit facility as of December 31, 2013, 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 %

The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under the Company's credit facility as of February 12, 2014, December 31, 2013, and December 31, 2012:

	As of February 12, 2014	As of December 31, 2013	As of December 31, 2012
	(in millions)		
Credit facility balance	$—	$—	$340.0
Letters of credit [1]	$0.8	$0.8	$0.8
Available borrowing capacity	$1,299.2	$1,299.2	$659.2

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

Senior Notes

The Senior Notes line on the accompanying balance sheets, as of December 31, 2013, and 2012, consisted of the following:

	As of December 31,	
	2013	2012
	(in thousands)	
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	400,000
5.0% Senior Notes due 2024	500,000	—
Total long-term debt	$1,600,000	$1,100,000

The Senior 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 Senior Notes. The Company is subject to certain covenants under the indenture governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by the restricted payment covenant. The Company was in compliance with all covenants under its Senior Notes as of December 31, 2013, and through the filing date of this report.

2024 Notes

On May 20, 2013, the Company issued $500.0 million in aggregate principal amount of 5.0% Senior Notes due 2024. The 2024 Notes were issued at par and mature on January 15, 2024. The Company received net proceeds of $490.2 million after deducting fees of $9.8 million, which are being amortized as deferred financing costs over the life of the 2024 Notes. The net proceeds were used to reduce the Company's outstanding credit facility balance.

Prior to July 15, 2016, the Company may redeem, on one or more occasions, up to 35 percent of the aggregate principal amount of the 2024 Notes with the net cash proceeds of certain equity offerings at a redemption price of 105% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 2024 Notes, in whole or in part, at any time prior to July 15, 2018, at a redemption price equal to 100 percent of the principal amount of the 2024 Notes to be redeemed, plus a specified make-whole premium and accrued and unpaid interest to the applicable redemption date.

On or after July 15, 2018, the Company may also redeem all or, from time to time, a portion of the 2024 Notes at the redemption prices set forth below, during the twelve-month period beginning on July 15 of each applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2018	102.500	%
2019	101.677	%
2020	100.833	%
2021 and thereafter	100.000	%

Additionally, on May 20, 2013, the Company entered into a registration rights agreement that provides holders of the 2024 Notes certain registration rights under the Securities Act. Pursuant to the registration rights agreement, the Company is required to file an exchange offer registration statement with the SEC with respect to its offer to exchange the 2024 Notes for substantially identical notes that are registered under the Securities Act. Under certain circumstances, the Company has agreed to file a shelf registration statement relating to the resale of the 2024 Notes in lieu of a registered exchange offer. If the registration statement related to the exchange offer is not declared effective on or before May 20, 2014, or if the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, the Company has agreed to pay additional interest with respect to the 2024 Notes in an amount not to exceed one percent of the principal amount of the 2024 Notes until the exchange offer is completed or the shelf registration statement is declared effective.

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	%

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. The Company satisfied its obligations to exchange its outstanding $400.0 million of its 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	%

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 credit facility, to fund the Company's ongoing capital expenditure program, and for general corporate purposes.

The Company may 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	%

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.

3.50% Senior Convertible Notes

On April 2, 2012, the Company called for redemption all of its outstanding 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.

Capitalized Interest

Capitalized interest costs for the Company for the years ended December 31, 2013, 2012, and 2011, were $11.0 million, $12.1 million, and $10.8 million, respectively.

Note 6 – Commitments and Contingencies

Commitments

The Company has entered into various agreements, which include drilling rig contracts of $65.7 million, gathering, processing, and transportation through-put commitments of $1.1 billion, office leases, including maintenance, of $69.4 million, and other miscellaneous contracts and leases of $7.6 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)
2014	$ 179,118
2015	147,119
2016	144,438
2017	132,559
2018	128,418
Thereafter	481,947
Total	$ 1,213,599

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 1,807 Bcf of natural gas and 53 MMBbl of oil. These contracts expire at various dates through 2023 and the total amount of the commitment is approximately $1.1 billion. 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. During the third quarter of 2013, the Company entered into an office lease with an initial term of 12 years and minimum lease payments of $12.9 million over the term beginning on the commencement date, which is anticipated to be in the second quarter of 2014. Rent expense for 2013, 2012, and 2011, was $5.7 million, $5.4 million, and $3.7 million, respectively. The Company also leases office equipment under various operating leases.

In addition to the amounts in the above table, the Company has committed to pay its portion of the development of infrastructure in its outside operated Eagle Ford shale play. The system owners unanimously approved budgeted costs for 2014, of which the Company is committed to pay approximately $33.0 million for the upcoming year.

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.

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 responded to the petition and denied the allegations. The district court did not rule on Chieftain's motion to certify the putative class, and stayed all proceedings until the United States Court of Appeals for the Tenth Circuit issues its rulings on class certification in two similar royalty class action lawsuits. On July 9, 2013, the Tenth Circuit issued its opinions, reversing the trial courts' grant of class certification and remanding the matters to the trial courts for those cases. The district court presiding over the Company's case subsequently lifted its stay, and the Company expects Chieftain to file a new motion for class certification in the first half of 2015.

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 paid royalties under Oklahoma law and has and will continue to vigorously defend this case. On December 30, 2013, the Company sold a substantial portion of its assets that were subject to this matter, and the buyer assumed any such liabilities related to such properties.

In an unrelated matter, as of and for the year ended December 31, 2013, other operating expenses includes $23.1 million related to an agreed clarification concerning royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage. As of December 31, 2013, $9.6 million is included in accounts payable and accrued expenses as $13.5 million was paid in 2013.

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 expense, lease operating expense, and exploration expense in the accompanying statements of operations are $41.8 million, $16.3 million, and $23.9 million of cash bonus expense related to the specific performance years ended December 31, 2013, 2012, and 2011, 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, 2013, 3.8 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 stock option, a restricted share, a RSU, or a PSU counts as one share against the number of shares available to be granted under the Equity Plan. Each PSU has the potential to count as two shares against the number of shares available to be granted under the Equity Plan based on the final performance multiplier. 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.

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants PSUs to eligible employees as a part of its equity 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 performance of the Company's TSR compared with the annualized TSR 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 $16.8 million, $18.2 million, and $19.7 million for the years ended December 31, 2013, 2012, and 2011, respectively. As of December 31, 2013, there was $18.8 million of total unrecognized expense related to PSUs, which is being amortized through 2016.

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

	For the Years Ended December 31,					
	2013		2012		2011	
	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)	669,308	$ 63.91	885,894	$ 57.52	1,110,666	$ 39.48
Granted(1)	274,831	$ 64.13	314,853	$ 51.98	266,282	$ 91.45
Vested(1)	(345,005)	$ 60.06	(493,679)	$ 44.72	(364,172)	$ 35.74
Forfeited(1)	(26,665)	$ 69.74	(37,760)	$ 65.35	(126,882)	$ 33.32
Non-vested at end of year(1)	572,469	$ 66.07	669,308	$ 63.91	885,894	$ 57.52

(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 2013, 2012, and 2011 was $17.6 million, $16.4 million, and $24.3 million for the 2013, 2012, and 2011 grants, respectively. The PSUs granted in 2013 will remain unvested until the third anniversary date of their issuance, at which time they will fully vest. 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, 2/7ths, and 4/7ths, respectively, on the first three anniversary dates of their issuances.

The total fair value of PSUs that vested during the years ended December 31, 2013, 2012, and 2011 was $20.7 million, $22.1 million, and $13.0 million, respectively.

During the year ended December 31, 2013, the Company settled PSUs that were granted in 2010, and which had earned a 1.725-times multiplier, by issuing a net 387,461 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, 200,050 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs for 2013.

During the year ended December 31, 2012, the Company settled PSUs that were granted in 2009, which earned a 2.0-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, 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, and which had 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, 2013, 2012, and 2011, was $13.1 million, $9.8 million, and $5.3 million, respectively. As of December 31, 2013, there was $19.3 million of total unrecognized expense related to unvested RSU awards, which is being amortized through 2016. 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,					
	2013		2012		2011	
	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	496,244	$51.81	308,877	$44.33	333,359	$31.16
Granted	329,939	$60.01	379,332	$49.47	98,952	$72.69
Vested	(207,376)	$49.73	(166,672)	$32.72	(105,820)	$30.61
Forfeited	(38,376)	$54.37	(25,293)	$51.06	(17,614)	$36.80
Non-vested at end of year	580,431	$57.05	496,244	$51.81	308,877	$44.33

The fair value of RSUs granted in 2013, 2012, and 2011 was $19.8 million, $18.8 million, and $7.2 million, respectively. The RSUs granted in 2013 and 2012 will vest 1/3 on each of the first three anniversary dates of the awards. RSUs granted prior to 2012 vest 1/7th, 2/7^{ths}, and 4/7^{ths}, respectively, on the first three anniversary dates of their issuances.

The total fair value of RSUs that vested during the years ended December 31, 2013, 2012, and 2011, was $10.3 million, $5.4 million, and $3.2 million, respectively.

During the years ended December 31, 2013, 2012, and 2011, the Company settled 207,378, 166,670, and 105,820 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 139,391, 116,813, and 72,305 for 2013, 2012, and 2011, respectively. The remaining 67,987, 49,857, and 33,515 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs for 2013, 2012, and 2011, 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, 2013, 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, 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
For the year ended December 31, 2013			
Outstanding, start of year	267,846	$14.95	
Exercised	(228,758)	$13.92	$12,326,994
Forfeited	—	$—	
Outstanding, end of year	39,088	$20.87	$2,432,837
Vested and exercisable at end of year	39,088	$20.87	$2,432,837

A summary of additional information related to options outstanding as of December 31, 2013, follows:

	Options Outstanding and Exercisable	
Exercise Price[1]	Number Of Options Outstanding and Exercisable	Weighted-Average Remaining Contractual Life (in years)
$20.87	39,088	1
Total	39,088	

(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 no excess tax benefits for the years ended December 31, 2013, 2012, and 2011. Cash received from exercises under all share-based payment arrangements for the years ended December 31, 2013, 2012, and 2011, was $3.2 million, $3.0 million, and $5.0 million, respectively.

Director Shares

In 2013, 2012, and 2011, the Company issued 28,169, 30,486, and 21,568 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 $1.4 million, $1.3 million, and $1.2 million for the years ended December 31, 2013, 2012, and 2011, 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 1.2 million shares available under the ESPP for issuance as of December 31, 2013. Shares issued under the ESPP totaled 77,427 in 2013, 66,485 in 2012, and 41,358 in 2011. Total proceeds to the Company for the issuance of these shares were $3.7 million in 2013, $2.8 million in 2012, and $2.3 million in 2011.

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.

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,					
	2013		2012		2011	
Risk free interest rate	0.1	%	0.1	%	0.2	%
Dividend yield	0.2	%	0.2	%	0.2	%
Volatility factor of the expected market price of the Company's common stock	41.1	%	47.8	%	36.3	%
Expected life (in years)	0.5		0.5		0.5	

The Company expensed $1.1 million, $948,000, and $682,000 for the years ended December 31, 2013, 2012, and 2011, 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 a maximum of 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. Beginning in 2014, the Company will also match employee contributions up to six percent of the employee's bonus paid pursuant to the Company's cash bonus plan. The Company’s matching contributions to the 401(k) Plan were $4.2 million, $3.5 million, and $2.9 million for the years ended December 31, 2013, 2012, and 2011, 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 each 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,		
	2013	2012	2011
	(in thousands)		
General and administrative expense	$13,734	$15,565	$19,326
Exploration expense	1,310	1,751	2,091
Total	$15,044	$17,316	$21,417

Additionally, the Company made or accrued cash payments under the Net Profits Plan of $10.3 million, $2.3 million, and $6.3 million for the years ended December 31, 2013, 2012, and 2011, respectively, as a result of divestiture proceeds. The cash payments are accounted for as a reduction in the gain (loss) on divestiture activity line item in the accompanying statements of operations.

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 paid to employees 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,	
	2013	2012
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$40,237	$29,480
Service cost	6,291	4,934
Interest cost	1,627	1,374
Plan amendments	—	—
Actuarial loss (gain)	(1,577)	5,467
Benefits paid	(3,293)	(1,018)
Projected benefit obligation at end of year	43,285	40,237
Change in plan assets:		
Fair value of plan assets at beginning of year	20,254	13,940
Actual return on plan assets	2,726	1,952
Employer contribution	4,971	5,380
Benefits paid	(3,293)	(1,018)
Fair value of plan assets at end of year	24,658	20,254
Funded status at end of year	$(18,627)	$(19,983)

The Company’s underfunded status for the Pension Plans for the years ended December 31, 2013 and 2012, is $18.6 million and $20.0 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, 2013. 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.

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

	As of December 31,	
	2013	2012
	(in thousands)	
Projected benefit obligation	$43,285	$40,237
Accumulated benefit obligation	$32,396	$29,437
Less: Fair value of plan assets	(24,658)	(20,254)
Underfunded accumulated benefit obligation	$7,738	$9,183

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, 2013 and 2012, consist of:

	As of December 31,	
	2013	2012
	(in thousands)	
Unrecognized actuarial losses	$8,439	$12,427
Unrecognized prior service costs	136	153
Unrecognized transition obligation	—	—
Accumulated other comprehensive loss	$8,575	$12,580

The estimated net loss that will be amortized from accumulated other comprehensive loss into net periodic benefit cost over the next fiscal year is $436,000.

Pre-tax changes recognized in other comprehensive income (loss) during 2013, 2012, and 2011, were as follows:

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Net actuarial gain (loss)	$2,766	$(4,680)	$(3,014)
Prior service cost	—	—	(170)
Less: Amortization of:			
Prior service cost	(17)	(17)	—
Actuarial loss	(1,222)	(754)	(405)
Total other comprehensive income (loss)	$4,005	$(3,909)	$(2,779)

Components of Net Periodic Benefit Cost for Both Pension Plans

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Components of net periodic benefit cost:			
Service cost	$6,291	$4,934	$3,800
Interest cost	1,627	1,374	1,184
Expected return on plan assets that reduces periodic pension cost	(1,538)	(1,165)	(880)
Amortization of prior service cost	17	17	—
Amortization of net actuarial loss	1,222	754	405
Net periodic benefit cost	$7,619	$5,914	$4,509

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,		
	2013	2012	2011
Projected benefit obligation			
Discount rate	5.0%	3.9%	4.7%
Rate of compensation increase	6.2%	6.2%	6.2%
Net periodic benefit cost			
Discount rate	3.9%	4.7%	5.3%
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 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	2014		2013		2012	
Equity securities	44.0	%	43.6	%	42.7	%
Debt securities	33.0	%	32.2	%	32.8	%
Other	23.0	%	24.2	%	24.5	%
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 2013 and 2012. 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 is not expected to 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, 2013, 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	—	%	$—	$—	$—	$—
Equity Securities						
Domestic [1]	29.9	%	7,371	4,888	2,483	—
International [2]	13.7	%	3,373	3,373	—	—
Total Equity Securities	43.6	%	10,744	8,261	2,483	—
Fixed Income Securities						
High-Yield Bonds [3]	5.9	%	1,448	1,448	—	—
Core Fixed Income [4]	20.3	%	5,006	5,006	—	—
Floating Rate Corp Loans [5]	6.0	%	1,483	1,483	—	—
Total Fixed Income Securities	32.2	%	7,937	7,937	—	—
Other Securities:						
Commodities [6]	3.8	%	945	945	—	—
Real Estate [7]	3.5	%	859	—	—	859
Hedge Fund [8]	14.3	%	3,517	955	—	2,562
Collective Investment Trusts [9]	2.6	%	656	—	656	—
Total Other Securities	24.2	%	5,977	1,900	656	3,421
Total Investments	100.0	%	$24,658	$18,098	$3,139	$3,421

(1) Level 1 equity securities consist of United States large and small capitalization companies, which are actively traded securities that can be sold upon demand. Level 2 equity securities are investments in a collective investment fund that is valued at net asset value based on the value of the underlying investments and total units outstanding on a daily basis. The objective of this fund is to approximate the S&P 500 by investing in one or more collective investment funds.

(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.

(9) Collective investment trusts invest in short-term investments and are valued at the net asset value of the collective investment trust. The net asset value, as provided by the trustee, is used as a practical expedient to estimate fair

value. The net asset value is based on the fair value of the underlying investments held by the fund less its liabilities.

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

December 31, 2012	$2,384
Purchases	742
Realized gain on assets	161
Unrealized gain on assets	134
December 31, 2013	$3,421

The fair value of the Company’s pension plan assets as of December 31, 2012, 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

Contributions

The Company contributed $5.0 million, $5.4 million, and $5.3 million, to the Pension Plans in the years ended December 31, 2013, 2012, and 2011, respectively. The Company is expected to make a $4.3 million contribution to the Pension Plans in 2014.

Benefit Payments

The Pension Plans made actual benefit payments of $3.3 million, $1.0 million, and $1.5 million in the years ended December 31, 2013, 2012, and 2011, respectively. Expected benefit payments over the next 10 years are as follows:

Years Ending December 31,	(in thousands)
2014	$2,120
2015	$2,837
2016	$3,287
2017	$3,993
2018	$4,407
2019 through 2023	$33,031

Note 9 – 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 a 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. Cash paid to settle asset retirement obligations is included in the operating section of the Company’s accompanying statements of cash flows.

The Company’s estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimates as to the cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company’s abandonment liabilities range from 5.5 percent to 12 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives or if federal or state regulators enact new requirements regarding the abandonment of wells.

A reconciliation of the Company's asset retirement obligation liability is as follows:

	As of December 31,	
	2013	2012
	(in thousands)	
Beginning asset retirement obligation	$120,518	$95,906
Liabilities incurred	18,682	13,050
Liabilities settled	(33,129)	(8,101)
Accretion expense	5,997	4,679
Revision to estimated cash flows	9,118	14,984
Ending asset retirement obligation	$121,186	$120,518

As of December 31, 2013 and 2012, the Company had $3.0 million and $1.4 million, respectively, of asset retirement obligation associated with the oil and gas properties held for sale included in a separate line item on the Company's accompanying balance sheets. Additionally, as of December 31, 2013 and 2012, accounts payable and accrued expenses contain $2.5 million and $6.2 million, respectively, related to the Company's current asset retirement obligation liability for estimated plugging and abandonment costs associated with platforms that are being relinquished or retired.

Note 10 – Derivative Financial Instruments

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

The Company has entered into various commodity derivative contracts to mitigate a portion of the exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. The Company's derivative contracts in place include swap and collar arrangements for oil, gas, and NGLs.

As of December 31, 2013, the Company has commodity derivative contracts outstanding through the second quarter of 2018 for a total of 18.8 million Bbls of oil production, 265.9 million MMBtu of gas production, and 2.5 million Bbls of NGL production. As of February 12, 2014, the Company had commodity derivative contracts in place through the second quarter of 2018 for a total of 17.5 million Bbls of oil, 237.9 million MMBtu of gas, and 4.0 million Bbls of NGLs. These volumes are net of scheduled January 2014 settlements, as well as the early settlement of 18.0 million MMBtu of gas swaps and collars in January 2014 due to the divestiture of assets in our Mid-Continent region at the end of 2013.

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

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of December 31, 2013:

Oil Contracts

Oil Swaps

Contract Period	Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)
First quarter 2014	2,600,000	$96.92
Second quarter 2014	2,373,000	$94.95
Third quarter 2014	973,000	$95.25
Fourth quarter 2014	891,000	$95.16
2015	2,911,000	$89.06
2016	2,704,000	$85.19
All oil swaps*	12,452,000	

*Oil swaps are comprised of NYMEX WTI (97%) and Argus LLS (3%).

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)
First quarter 2014	694,000	$80.97	$115.07
Second quarter 2014	431,000	$85.00	$102.50
Third quarter 2014	973,000	$85.00	$102.58
Fourth quarter 2014	923,000	$85.00	$102.63
2015	3,366,000	$85.00	$94.25
All oil collars	6,387,000		

Natural Gas Contracts

Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)
First quarter 2014	33,651,000	$4.25
Second quarter 2014	25,729,000	$3.96
Third quarter 2014	26,398,000	$4.01
Fourth quarter 2014	23,965,000	$4.01
2015	63,317,000	$4.03
2016	39,014,000	$4.18
2017	23,430,000	$4.21
2018	10,200,000	$4.31
All gas swaps*	245,704,000	

*Natural gas swaps are comprised of IF El Paso Permian (3%), IF HSC (77%), IF NGPL TXOK (3%), IF NNG Ventura (2%), IF PEPL (6%), IF Reliant N/S (8%), and IF NGPL MidCon (1%).

Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)
First quarter 2014	1,540,000	$4.39	$5.58
Second quarter 2014	4,194,000	$4.38	$5.29
2015	14,480,000	$3.96	$4.30
All gas collars*	20,214,000		

*Natural gas collars are comprised of IF El Paso Permian (2%), IF HSC (57%), IF NGPL TXOK (3%), IF NNG Ventura (5%), IF PEPL (7%), IF Reliant N/S (14%), and IF TETCO STX (12%).

NGL Contracts
NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
First quarter 2014	913,000	$59.72
Second quarter 2014	565,000	$63.22
Third quarter 2014	544,000	$62.34
Fourth quarter 2014	527,000	$61.57
All NGL swaps*	2,549,000	

*NGL swaps are comprised of OPIS IsoButane Mt Belv Non TET (2%), OPIS Natural Gasoline Mt Belv Non TET (34%), OPIS NButane Mt Belv Non TET (3%), and OPIS Propane Mt Belv TET (61%).

Commodity Derivative Contracts Entered into After December 31, 2013

The following tables summarize all commodity derivative contracts entered between January 1, 2014 and February 12, 2014:
Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
First quarter 2014	261,000	$4.39
Second quarter 2014	365,000	$3.84
Third quarter 2014	341,000	$3.89
Fourth quarter 2014	321,000	$3.97
2015	1,133,000	$3.72
2016	69,000	$4.12
All gas swaps*	2,490,000	

*Natural gas swaps are comprised of IF NNG Ventura (30%) and IF CIG N System (70%).

NGL Contracts
NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
First quarter 2014	516,000	$54.85
Second quarter 2014	531,000	$52.53
Third quarter 2014	416,000	$52.47
Fourth quarter 2014	334,000	$52.52
All NGL swaps*	1,797,000	

*NGL swaps are comprised of OPIS Natural Gasoline Mt Belv Non TET (17%) and OPIS Propane Mt Belv TET (83%).

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net asset of $21.5 million and $38.7 million at December 31, 2013 and 2012, respectively.

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of December 31, 2013			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current assets	$21,559	Current liabilities	$26,380
Commodity Contracts	Noncurrent assets	30,951	Noncurrent liabilities	4,640
Derivatives not designated as hedging instruments		$52,510		$31,020

	As of December 31, 2012			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current assets	$37,873	Current liabilities	$8,999
Commodity Contracts	Noncurrent assets	16,466	Noncurrent liabilities	6,645
Derivatives not designated as hedging instruments		$54,339		$15,644

Offsetting of Derivative Assets and Liabilities

As of December 31, 2013 and 2012, all derivative instruments held by the Company were subject to enforceable master netting arrangements held by various financial institutions. In general, the terms of the Company’s agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency. The Company’s agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's derivative contracts:

	Derivative Assets		Derivative Liabilities	
	As of December 31,		As of December 31,	
Offsetting of Derivative Assets and Liabilities	2013	2012	2013	2012
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$52,510	$54,339	$(31,020)	$(15,644)
Amounts not offset in the accompanying balance sheets	(30,652)	(13,400)	30,652	13,400
Net amounts	$21,858	$40,939	$(368)	$(2,244)

Discontinuance of Cash Flow Hedge Accounting

Prior to January 1, 2011, the Company designated its commodity derivative contracts as cash flow hedges, for which unrealized changes in fair value were recorded to AOCIL, to the extent the hedges were effective. As of January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010. As a result, subsequent to December 31, 2010, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCIL. The Company had no derivatives designated as cash flow hedges for the years ended December 31, 2013, and 2012.

As a result of discontinuing hedge accounting on January 1, 2011, fair values at December 31, 2010, were frozen in AOCIL as of the de-designation date and were reclassified into earnings as the original derivative transactions settled. As of December 31, 2013, all commodity derivative contracts that had been previously designated as cash flow hedges have settled and have been reclassified into earnings from AOCIL. Please refer to Note 11 - Fair Value Measurements for more information regarding the Company’s derivative instruments, including its valuation techniques.

The following table summarizes the components of derivative (gain) loss presented in the accompanying statements of operations:

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Derivative cash settlement (gain) loss:			
Oil contracts	$15,161	$11,893	$22,633
Gas contracts	(30,338)	(47,270)	(10,711)
NGL contracts	(6,885)	(8,887)	13,749
Total derivative cash settlement (gain) loss (1)	(22,062)	(44,264)	25,671
Derivative (gain) loss:			
Oil contracts	(496)	(31,981)	(3,391)
Gas contracts	16,285	31,777	(64,310)
NGL contracts	3,193	(11,162)	4,944
Total derivative gain (2)	$(3,080)	$(55,630)	$(37,086)

(1) Total derivative cash settlement gain (loss) is reported in the derivative cash settlement gain (loss) line item on the consolidated statements of cash flows within net cash provided by operating activities.

(2) Total derivative gain is reported in the derivative gain line item on the consolidated statements of cash flows within net cash provided by operating activities.

The following table details the effect of derivative instruments on AOCIL and the accompanying statements of operations (net of income tax):

	Derivatives	Location on Accompanying Statements of Operations	For the Years Ended December 31, 2013	2012	2011
			(in thousands)		
Amount reclassified from AOCIL	Commodity Contracts	Realized hedge gain (loss)	$1,115	$(2,264)	$12,997

The realized net hedge loss for the year ended December 31, 2013, net hedge gain for the year ended December 31, 2012, and net hedge loss for the year ended December 31, 2011, shown net of income tax in the table above, are comprised of realized cash settlements on commodity derivative contracts that were previously designated as cash flow hedges. Realized hedge gains or losses from the settlement of commodity derivatives previously designated as cash flow hedges are reported in the total operating revenues and other income section of the accompanying statements of operations. The Company realized a pre-tax net loss of $1.8 million, a pre-tax net gain of $3.9 million, and a pre-tax net loss of $20.7 million from its commodity derivative contracts for the years ended December 31, 2013, 2012, and 2011, respectively.

As noted above, effective January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges. No new gains or losses are deferred in AOCIL at December 31, 2013, and 2012, respectively.

Credit Related Contingent Features

As of December 31, 2013, and through the filing date of this report, all of the Company's derivative counterparties were members of the Company's credit facility syndicate. The Company's obligations under its credit facility and derivative contracts are secured by liens on substantially all of the Company's proved oil and gas properties.

Convertible Note Derivative Instrument

The contingent interest provision of the 3.50% Senior Convertible Notes was an embedded derivative instrument. The 3.50% Senior Convertible Notes were settled during the second quarter of 2012. Please refer to Note 5 - Long-term Debt for additional discussion.

Note 11 – Fair Value Measurements

The Company follows fair value measurement authoritative accounting guidance for all assets and liabilities measured at fair value. That authoritative accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – significant inputs to the valuation model are unobservable

The following table is a listing of the Company's assets and liabilities that are measured at fair value and where they were classified within the fair value hierarchy as of December 31, 2013:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$52,510	$—
Proved oil and gas properties (2)	$—	$—	$62,178
Unproved oil and gas properties (2)	$—	$—	$3,280
Oil and gas properties held for sale (2)	$—	$—	$650
Liabilities:			
Derivatives (1)	$—	$31,020	$—
Net Profits Plan (1)	$—	$—	$56,985

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.

(2) This represents a non-financial asset that is measured at fair value on a nonrecurring basis.

The following table is a listing of the Company’s assets and liabilities that are measured at fair value and where they were classified within the hierarchy as of December 31, 2012:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$54,339	$—
Proved oil and gas properties (2)	$—	$—	$209,959
Unproved oil and gas properties (2)	$—	$—	$42,765
Liabilities:			
Derivatives (1)	$—	$15,644	$—
Net Profits Plan (1)	$—	$—	$78,827

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset that is measured at fair value on a nonrecurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, counterparties’ credit ratings, the Company’s credit rating, and the time value of money. These valuations are then compared to the respective counterparties’ mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may require counterparties to post collateral if their ratings deteriorate. Currently, one counterparty posts collateral when requested by the Company. In some instances the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company’s credit quality on the fair value of any derivative liability position. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk and takes into account the Company’s credit rating, current credit facility margins, and any change in such margins since the last measurement date. All of the Company’s derivative counterparties are members of the Company’s credit facility bank syndicate.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with accounting authoritative guidance and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Refer to Note 10 - Derivative Financial Instruments for more information regarding the Company's derivative instruments.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable and are therefore classified as Level 3 inputs. The Company employs the income valuation technique, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil, gas, and NGL commodity prices driving net cash flows and the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and lower commodity prices result in a smaller Net Profits Plan liability.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. A discount rate of 12 percent is used to calculate this liability, which is intended to represent the Company's best estimate of the present value of expected future payments under the Net Profits Plan.

The Company's estimate of its liability is highly dependent on commodity prices, cost assumptions, discount rates, and overall market conditions. The Company regularly assesses the current market environment. The Net Profits Plan liability is determined using price assumptions of five one-year strip prices with the fifth year's pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of the forecasted production covered by derivatives contracts in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the oil, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at December 31, 2013, would differ by approximately $5 million. A one percent increase in the discount rate would decrease the liability by approximately $2 million, whereas a one percent decrease in the discount rate would increase the liability by approximately $2 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and actual costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of its Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value of the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates.

The following table reflects the activity for the Company's Net Profits Plan liability measured at fair value using Level 3 inputs:

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Beginning balance	$78,827	$107,731	$135,850
Net increase (decrease) in liability (1)	3,527	(9,251)	2,269
Net settlements (1) (2) (3)	(25,369)	(19,653)	(30,388)
Transfers in (out) of Level 3	—	—	—
Ending balance	$56,985	$78,827	$107,731

(1) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(2) Settlements represent cash payments made or accrued under the Net Profits Plan. The amounts in the table include cash payments made or accrued under the Net Profits Plan of $10.3 million, $2.3 million, and $6.3 million relating to divestiture proceeds for the years ended December 31, 2013, 2012, and 2011, respectively.

(3) During 2011, the Company elected to cash out several Net Profits Plan pools with a $2.6 million direct payment. As a result, the Company reduced its Net Profits Plan liability by that amount. There was no impact on the accompanying statements of operations for the period ended December 31, 2011, related to these settlements.

Long-term Debt

The following table reflects the fair value of the Senior Notes measured at fair value using Level 1 inputs based on quoted secondary market trading prices. The Senior Notes were not presented at fair value on the accompanying balance sheets as of December 31, 2013 or 2012, as they are recorded at historical value.

	As of December 31,	
	2013	2012
	(in thousands)	
2019 Notes	$374,290	$371,875
2021 Notes	$373,625	$371,070
2023 Notes	$422,000	$424,200
2024 Notes (1)	$475,315	$—

(1) The 2024 Notes were issued on May 20, 2013.

The carrying value of the Company's credit facility approximates its fair value, as the applicable interest rates are floating, based on prevailing market rates.

Proved and Unproved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company's management. The calculation of the discount rate is based on the best information available and was estimated to be 12 percent as of December 31, 2013, and 2012. The Company believes that the discount rate is representative of current market conditions and takes into account estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. 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. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above.
As a result of asset write-downs, the proved oil and gas properties measured at fair value within the accompanying balance sheets totaled $62.2 million and $210.0 million as of December 31, 2013, and 2012, respectively.
Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes a market approach, which estimates acreage value based on the price received for similar acreage in recent transactions by the Company or other market participants in the principal market.
As a result of asset write-downs, unproved oil and gas properties measured at fair value within the accompanying balance sheets totaled $3.3 million as of December 31, 2013 and $42.8 million at December 31, 2012.

Acquisitions of proved and unproved properties are measured at fair value as of the acquisition date using a discounted cash flow model similar to the Company’s approach in measuring the fair value of proved and unproved properties, as discussed in the paragraphs above. Due to the unobservable characteristics of the inputs, the fair value of acquired properties are considered Level 3 within the fair value hierarchy.

Materials Inventory

Materials inventory is valued at the lower of cost or market. The Company uses Level 2 inputs to measure the fair value of materials inventory, which is primarily comprised of tubular goods. The Company uses third party market quotes and compares the quotes to the book value of the materials inventory. If the book value exceeds the quoted market price, the Company reduces the book value to the market price. The considered factors result in an estimated exit-price. Management believes this approach provides a reasonable and consistent methodology for valuing materials inventory. There were no materials inventory measured at fair value within the accompanying balance sheets at December 31, 2013 and 2012.
Asset Retirement Obligations
The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company’s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value within the accompanying balance sheets at December 31, 2013 and 2012.

Note 12 - Acquisition and Development Agreement

In June 2011, the Company entered into an Acquisition and Development Agreement with Mitsui. Pursuant to the Acquisition and Development Agreement, the Company agreed to transfer to Mitsui a 12.5 percent working interest in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick, and Webb Counties, Texas. As consideration for the oil and gas interests transferred, Mitsui agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to the Company's remaining interest in these assets until Mitsui has expended an aggregate $680.0 million on behalf of the Company. Based on the Company's forecast of the operator's drilling plans, the carry will be fully utilized in early 2014. The Acquisition and Development Agreement also provided for reimbursement of capital expenditures and other costs, net of revenues, paid by the Company that were attributable to the transferred interest during the period between the effective date and the closing date, which the parties agreed would be applied over the carry period to cover the Company's remaining 10 percent of drilling and completion costs for the affected acreage.

As of December 31, 2013, the Company held $95.0 million in cash that is contractually restricted for use in the development of assets covered by the Acquisition and Development Agreement. This cash relates to the reimbursement of net costs for the period between the effective date and closing date, as discussed above, as well as an estimate of 90 percent of two months of activity of the Company's proportionate share of estimated drilling and completion costs. This restricted cash is classified as a noncurrent asset in the accompanying balance sheets. The Company has recorded a corresponding liability equal to the restricted cash balance. The portion of the liability related to development operations expected to occur within the next year is recorded in accounts payable and accrued expenses within the accompanying balance sheets. The portion of the liability related to development operations expected to occur more than one year in the future is recorded in other noncurrent liabilities within the accompanying balance sheets. As the remaining development operations are expected to be completed within the next year, the entire amount is recorded in accounts payable and accrued expenses within the accompanying balance sheets as of December 31, 2013. There was no net impact on the accompanying statements of cash flows as restricted cash was offset against the corresponding liability in investing activities. There is no direct impact to the accompanying statements of operations as a result of the Acquisition and Development Agreement, with the exception of legal and commission costs associated with the execution of the arrangement which were expensed in 2011. Of the original $680.0 million carry amount, $573.8 million had been spent as of December 31, 2013.

Note 13 - Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2013, 2012, and 2011. The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same year:

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Beginning balance on January 1,	$9,100	$18,600	$35,862
Additions to capitalized exploratory well costs pending the determination of proved reserves	34,527	9,100	15,618
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(9,100)	(5,865)	(32,880)
Capitalized exploratory well costs charged to expense	—	(12,735)	—
Ending balance at December 31,	$34,527	$9,100	$18,600

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for more than one year since the completion of drilling:

	As of December 31,		
	2013	2012	2011
	(in thousands)		
Exploratory well costs capitalized for one year or less	$34,527	$9,100	$15,618
Exploratory well costs capitalized for more than one year	—	—	2,982
Ending balance at December 31,	$34,527	$9,100	$18,600
Number of projects with exploratory well costs that have been capitalized more than a year	—	—	2

In the third quarter of 2012, the Company expensed $3.6 million of costs related to two exploratory wells that had been disclosed at December 31, 2011, as suspended well costs being capitalized for more than one year.

Supplemental Oil and Gas Information (unaudited)

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 Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Development costs (1)	$1,350,116	$1,346,216	$1,320,627
Exploration costs	168,612	220,921	177,465
Acquisitions			
Proved properties	29,859	5,773	—
Unproved properties (2)	172,546	114,971	55,237
Total, including asset retirement obligation (3)(4)	$1,721,133	$1,687,881	$1,553,329

(1) Includes facility costs of $49.5 million, $62.2 million, and $112.4 million for the years ended December 31, 2013, 2012, and 2011, respectively.

(2) Includes $58.5 million and $3.4 million of unproved properties acquired as part of a proved property acquisition for the years ended December 31, 2013 and 2012, respectively. The remaining balance relates to leasing activity.

(3) Includes capitalized interest of $11.0 million, $12.1 million, and $10.8 million for the years ended December 31, 2013, 2012, and 2011, respectively.

(4) Includes amounts relating to estimated asset retirement obligations of $26.8 million, $30.6 million, and $19.3 million for the years ended December 31, 2013, 2012, and 2011, respectively.

Oil and Gas Reserve Quantities

The reserve estimates presented below were made in accordance with GAAP requirements for disclosures about oil and gas producing activities and SEC rules for oil and gas reporting reserve estimation and disclosure.

Proved reserves are the estimated 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. All of the Company’s estimated proved reserves are located in the United States.

The table below presents a summary of changes in the Company's estimated proved reserves for each of the years in the three-year period ended December 31, 2013. The Company engaged Ryder Scott to audit internal engineering estimates for at least 80 percent of the PV-10 value of its estimated proved reserves in each year presented. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

	For the Years Ended December 31,								
	2013 (1)			2012 (2)			2011 (3)		
	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)
Total proved reserves									
Beginning of year	92.2	833.4	62.3	71.7	664.0	27.5	57.4	640.0	—
Revisions of previous estimate	(5.2)	68.8	(1.3)	(4.5)	(123.3)	(2.4)	(0.9)	(76.7)	15.6
Discoveries and extensions	34.6	399.2	39.8	17.1	297.4	30.6	26.9	223.5	17.8
Infill reserves in an existing proved field	21.6	118.7	13.2	19.2	125.1	12.7	2.8	14.8	0.5
Sales of reserves (4)	(3.4)	(85.1)	(0.6)	(1.0)	(11.0)	—	(6.4)	(37.3)	(2.9)
Purchases of minerals in place	0.7	3.6	—	0.1	1.2	—	—	—	—
Production	(13.9)	(149.3)	(9.5)	(10.4)	(120.0)	(6.1)	(8.1)	(100.3)	(3.5)
End of year (5)	126.6	1,189.3	103.9	92.2	833.4	62.3	71.7	664.0	27.5
Proved developed reserves									
Beginning of year	58.8	483.2	27.2	50.3	451.2	15.2	46.0	411.0	—
End of year	70.2	569.2	43.8	58.8	483.2	27.2	50.3	451.2	15.2
Proved undeveloped reserves									
Beginning of year	33.5	350.2	35.1	21.4	212.8	12.3	11.4	229.0	—
End of year	56.3	620.1	60.2	33.5	350.2	35.1	21.4	212.8	12.3

Note: Amounts may not recalculate due to rounding.

(1) For the year ended December 31, 2013, of the 5.0 MMBOE upward revision of a previous estimate, 0.6 MMBOE and 4.4 MMBOE relate to price and performance revisions, respectively. The prices used in the calculation of proved reserve estimates as of December 31, 2013, were $96.94 per Bbl, $3.67 per MMBtu, and $40.29 per Bbl for oil, natural gas, and NGLs respectively. These prices were two percent higher, 33 percent higher, and 12 percent lower, respectively, than the prices used in 2012. The Company added 195.5 MMBOE from its drilling program, the majority of which related to activity in the Eagle Ford shale in South Texas and Bakken/Three Forks plays in North Dakota. These additions are included in discoveries and extensions and infill reserves.

(2) For the year ended December 31, 2012, of the 27.4 MMBOE downward revision of a previous estimate, 12.1 MMBOE and 15.3 MMBOE relate to price and performance revisions, respectively. 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, natural gas, and NGLs respectively. These prices were two percent lower, 33 percent lower, and 23 percent lower, respectively, than the prices used in 2011. The Company added 150.0 MMBOE from its drilling program, the majority of which related to activity in the Eagle Ford shale in South Texas. These additions are included in discoveries and extensions and infill reserves.

(3) For the year ended December 31, 2011, of the 1.9 MMBOE upward revision of a previous estimate, (4.2) MMBOE and 6.1 MMBOE relate to price and performance revisions, respectively. The prices used in the calculation of proved

reserve estimates as of December 31, 2011, were $96.19 per Bbl and $4.12 per MMBtu, for oil and natural gas respectively. These prices were 21 percent higher and six percent lower, respectively, than the prices used in 2010. The per Bbl price used to estimate proved NGL reserves as of December 31, 2011 was $59.37. Performance revisions in 2011 resulted in a net 6.1 MMBOE increase in the estimate of proved reserves. This increase includes the impact of the Company's conversion to three stream production, which is partially offset by downward engineering revisions due primarily to the failure of Woodford shale wells in the Company's Mid-Continent region to satisfy internal economic hurdles. The Company added 87.7 MMBOE from its drilling program, the majority of which related to activity in the Eagle Ford shale in South Texas. These additions are included in discoveries and extensions and infill reserves.

(4) The Company divested of certain non-core assets during 2013, 2012, and 2011. Please refer to Note 3 - Divestitures and Assets Held for Sale for additional information.

(5) For the years ended December 31, 2013, 2012, and 2011, amounts included approximately 12, 50, and 29 MBOE respectively, representing the Company’s net underproduced gas balancing position.

Standardized Measure of Discounted Future Net Cash Flows

The Company computes a standardized measure of future net cash flows and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. Future cash inflows and production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated future reserve quantities. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using the current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10 percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved reserves in place at the end of the period using year-end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company’s expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. The following prices as adjusted for transportation, quality, and basis differentials were used in the calculation of the standardized measure:

	For the Years Ended December 31,		
	2013	2012	2011
Oil (per Bbl)	$90.19	$86.80	$88.00
Gas (per Mcf)	$3.99	$3.08	$4.72
NGLs (per Bbl)	$35.92	$41.00	$51.95

The following summary sets forth the Company’s future net cash flows relating to proved oil, gas, and NGL reserves based on the standardized measure.

	As of December 31,		
	2013	2012	2011
	(in thousands)		
Future cash inflows	$19,895,360	$13,129,243	$10,871,281
Future production costs	(7,771,747)	(5,013,720)	(3,786,887)
Future development costs	(2,891,325)	(1,742,978)	(1,036,352)
Future income taxes	(2,722,230)	(1,609,397)	(1,740,394)
Future net cash flows	6,510,058	4,763,148	4,307,648
10 percent annual discount	(2,500,619)	(1,742,134)	(1,727,608)
Standardized measure of discounted future net cash flows	$4,009,439	$3,021,014	$2,580,040

The principle sources of changes in the standardized measure of discounted future net cash flows are:

	For the Years Ended December 31,		
	2013	2012	2011
	(in thousands)		
Standardized measure, beginning of year	$3,021,014	$2,580,040	$1,666,367
Sales of oil, gas, and NGLs produced, net of production costs	(1,602,505)	(1,081,997)	(1,042,281)
Net changes in prices and production costs	142,199	(550,293)	454,646
Extensions, discoveries and other including infill reserves in an existing proved field, net of related costs	2,309,075	1,872,810	1,816,640
Sales of reserves in place	(259,031)	(41,020)	(369,820)
Purchase of reserves in place	30,771	3,785	—
Development costs incurred during the year	581,107	163,937	49,246
Changes in estimated future development costs	68,613	47,980	(31,410)
Revisions of previous quantity estimates	82,226	(452,454)	32,992
Accretion of discount	384,914	346,118	234,433
Net change in income taxes	(690,953)	53,005	(203,169)
Changes in timing and other	(57,991)	79,103	(27,604)
Standardized measure, end of year	$4,009,439	$3,021,014	$2,580,040

Quarterly Financial Information (unaudited)

The Company’s quarterly financial information for fiscal years 2013 and 2012 is as follows (in thousands, except per share amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth [2] Quarter
Year Ended December 31, 2013				
Total operating revenues	$484,180	$559,360	$613,107	$636,727
Total operating expenses	437,982	415,076	475,623	596,438
Income from operations	$46,198	$144,284	$137,484	$40,289
Income before income taxes	$27,109	$122,727	$113,024	$15,751
Net income	$16,727	$76,522	$70,690	$6,996
Basic net income per common share [1]	$0.25	$1.15	$1.06	$0.10
Diluted net income per common share [1]	$0.25	$1.13	$1.04	$0.10
Dividends declared per common share	$0.05	$—	$0.05	$—
Year Ended December 31, 2012				
Total operating revenues	$377,423	$304,420	$378,951	$444,308
Total operating expenses	321,198	252,029	421,787	530,105
Income (loss) from operations	$56,225	$52,391	$(42,836)	$(85,797)
Income (loss) before income taxes	$42,017	$39,684	$(61,072)	$(104,146)
Net income (loss)	$26,336	$24,889	$(38,336)	$(67,138)
Basic net income (loss) per common share [1]	$0.41	$0.39	$(0.58)	$(1.02)
Diluted net income (loss) per common share [1]	$0.39	$0.37	$(0.58)	$(1.02)
Dividends declared per common share	$0.05	$—	$0.05	$—

(1) Amounts may not sum due to rounding or the impact of quarterly net losses when computing year-to-date dilutive shares.

(2) The fourth quarter of 2013 and 2012 included $110.9 million and $170.4 million, respectively, of impairment of proved properties expense. Please refer to the caption Impairment of Proved and Unproved Properties included in Note 1 - Summary of Significant Accounting Policies for additional discussion.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

On September 10, 2012, SM Energy's Audit Committee of the Board of Directors approved the engagement of Ernst & Young LLP as the Company's independent registered accounting firm for the year ending December 31, 2013, replacing Deloitte & Touche LLP ("D&T").

The report of D&T on the Company's consolidated financial statements for the years ended December 31, 2012, and 2011, did not contain an adverse or disclaimer opinions, and was not qualified or modified.

During the years ended December 31, 2012, and 2011, there were no disagreements with D&T on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedures, which disagreements, if not resolved to the satisfaction of D&T, would have caused D&T to make reference to the subject matter of the disagreement in its report on the consolidated financial statements for such year.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company's internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that have a material effect on the financial statements.

Because of the inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. Even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of the changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (1992 framework).

Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2013.

The Company's independent registered public accounting firm has issued an attestation report on the Company's internal controls over financial reporting. That report immediately follows this report.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of SM Energy Company and subsidiaries

We have audited SM Energy Company and subsidiaries' internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). SM Energy Company and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, SM Energy Company and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of SM Energy Company and subsidiaries as of December 31, 2013, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for the year then ended and our report dated February 19, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Denver, Colorado
February 19, 2014

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item concerning SM Energy's Directors, Executive Officers, and corporate governance is incorporated by reference to the information provided under the captions Proposal 1 - Election of Directors, Executive Officers, and Corporate Governance in SM Energy's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from December 31, 2013.

The information required by this Item concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the information provided under the caption Section 16(a) Beneficial Ownership Reporting Compliance in SM Energy's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from December 31, 2013.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions, Executive Compensation and Director Compensation in SM Energy's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from December 31, 2013.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption Security Ownership of Certain Beneficial Owners and Management in SM Energy's definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from December 31, 2013.

Securities Authorized for Issuance Under Equity Compensation Plans. SM Energy has the Equity Plan under which options and shares of SM Energy common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. Our stockholders have approved this plan. See Note 7 – Compensation Plans included in Part II, Item 8 of this report for further information about the material terms of our equity compensation plans. The following table is a summary of the shares of common stock authorized for issuance under the equity compensation plans as of December 31, 2013:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Equity Incentive Compensation Plan			
Stock options and incentive stock options (1)	39,088	$ 20.87	
Restricted stock (1)(3)	580,431	N/A	
Performance share units (1)(3)(4)	807,406	N/A	
Total for Equity Incentive Compensation Plan	1,426,925	$ 20.87	3,813,900
Employee Stock Purchase Plan (2)	-	-	1,230,057
Equity compensation plans not approved by security holders	-	-	-
Total for all plans	1,426,925	$ 20.87	5,043,957

(1) In May 2006, the stockholders approved the Equity Plan to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, performance shares, performance units, and stock-based awards to key employees, consultants, and members of the Board of Directors of SM Energy or any affiliate of SM Energy. The Equity Plan serves as the successor to the St. Mary Land & Exploration Company Stock Option Plan, the St. Mary Land & Exploration Company Incentive Stock Option Plan, the SM Energy Company Restricted Stock Plan, and the SM Energy Company Non-Employee Director Stock Compensation Plan (collectively referred to as the “Predecessor Plans”). All grants of equity are now made under the Equity Plan, and no further grants will be made under the Predecessor Plans. Each outstanding award under a Predecessor Plan immediately prior to the effective date of the Equity Plan continues to be governed solely by the terms and conditions of the instruments evidencing such grants or issuances. Our Board of Directors approved amendments to the Equity Plan in 2009, 2010, and 2013 and each amended plan was approved by stockholders at the respective annual stockholders’ meetings. The awards granted in 2013, 2012, and 2011 under the Equity Plan were 632,939, 724,671, and 386,802, respectively.

(2) Under the SM Energy Company ESPP, eligible employees may purchase shares of our common stock through payroll deductions of up to 15 percent of their eligible compensation. 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 six-month offering period, and 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 Internal Revenue Code. Shares issued under the ESPP totaled 77,427, 66,485, and 41,358 in 2013, 2012, and 2011, respectively.

(3) RSUs and PSUs do not have exercise prices associated with them, but rather a weighted-average per share fair value, which is presented in order to provide additional information regarding the potential dilutive effect of the awards. The weighted-average grant date per share fair value for the outstanding RSUs and PSUs was $57.05 and $67.74, respectively. Please refer to Note 7 - Compensation Plans for additional discussion.

(4) The number of awards vested assumes a one multiplier. The final number of shares issued upon settlement may vary depending on the three-year multiplier determined at the end of the performance period under the Equity Plan, which ranges from zero to two.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information provided under the caption Certain Relationships and Related Transactions, and Corporate Governance, in SM Energy’s definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from December 31, 2013.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the caption Independent Registered Public Accounting Firm and Audit Committee Preapproval Policy and Procedures in SM Energy’s definitive proxy statement for the 2014 annual meeting of stockholders to be filed within 120 days from December 31, 2013.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:

Reports of Independent Registered Public Accounting Firms	88
Consolidated Balance Sheets	90
Consolidated Statements of Operations	91
Consolidated Statements of Comprehensive Income (Loss)	92
Consolidated Statements of Stockholders' Equity	93
Consolidated Statements of Cash Flows	94
Notes to Consolidated Financial Statements	96

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
2.1	Purchase and Sale Agreement dated June 9, 2011, among SM Energy Company, Statoil Texas Onshore Properties LLC, and Talisman Energy USA Inc. (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 and incorporated herein by reference)
2.2	Acquisition and Development Agreement dated June 29, 2011 between SM Energy Company and Mitsui E&P Texas LP (filed as Exhibit 2.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 and incorporated herein by reference)
2.3	First Amendment to Acquisition and Development Agreement dated October 13, 2011 between SM Energy Company and Mitsui E&P Texas (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 and incorporated herein by reference)
2.4*††	Purchase and Sale Agreement dated November 4, 2013, among SM Energy Company, EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., and EnerVest Energy Institutional Fund XIII-WIC, L.P.
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
3.2	Amended and Restated By-Laws of SM Energy Company amended effective as of January 1, 2013 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on January 7, 2013, and incorporated herein by reference)
4.1	Indenture related to the 3.50% Senior Convertible Notes due 2027, dated as of April 4, 2007, between St. Mary Land & Exploration Company and Wells Fargo Bank, National Association, as trustee (including the form of 3.50% Senior Convertible Note due 2027) (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on April 4, 2007 and incorporated herein by reference)
4.2	Indenture related to the 6.625% Senior Notes due 2019, dated as of February 7, 2011, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on February 10, 2011, and incorporated herein by reference)

4.3	Indenture related to the 6.50% Senior Notes due 2021, dated as of November 8, 2011, by and among SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on November 10, 2011, and incorporated herein by reference)
4.4	Indenture related to the 6.50% Senior Notes due 2023, dated June 29, 2012, between SM Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on July 3, 2012, and incorporated herein by reference)
4.5	Indenture related to the 5.0% Senior Notes due 2024, dated May 20, 2013, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on May 20, 2013, and incorporated herein by reference)
4.6	Registration Rights Agreement, dated May 20, 2013, by and among SM Energy Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wells Fargo Securities, LLC, and J.P. Morgan Securities LLC, as representatives of several purchasers (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on May 20, 2013, and incorporated herein by reference)
10.1†	Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.1 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.2†	Incentive Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.2 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.3†	Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference)
10.4†	Form of Amendment to Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.9 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference)
10.5†	Employment Agreement of A.J. Best dated May 1, 2006 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 4, 2006 and incorporated herein by reference)
10.6	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.7	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.8†	Equity Incentive Compensation Plan as Amended and Restated as of March 26, 2009 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 27, 2009, and incorporated herein by reference)
10.9†	Equity Incentive Compensation Plan As Amended and Restated as of April 1, 2010 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)
10.10s	SM Energy Company Equity Incentive Compensation Plan, As Amended as of July 30, 2010 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.11†	Third Amendment to Employee Stock Purchase Plan dated September 23, 2009 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, and incorporated herein by reference)
10.12†	Fourth Amendment to Employee Stock Purchase Plan dated December 29, 2009 (filed as Exhibit 10.46 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2009, and

incorporated herein by reference)

10.13s	Employee Stock Purchase Plan, As Amended and Restated as of July 30, 2010 (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.14†	Form of Performance Share and Restricted Stock Unit Award Agreement as of July 1, 2010 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.15†	Form of Performance Share and Restricted Stock Unit Award Notice as of July 1, 2010 (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.16†	Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.17***	Gas Services Agreement effective as of July 1, 2010 between SM Energy Company and Eagle Ford Gathering LLC (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.18s	Cash Bonus Plan, As Amended on July 30, 2010 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.19s	Net Profits Interest Bonus Plan, As Amended by the Board of Directors on July 30, 2010 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.20s	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan, As Amended as of July 30, 2010 (filed as Exhibit 10.8 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.21†	Form of Amendment to Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 29, 2010, and incorporated herein by reference)
10.22†	Amendment to A.J. Best Employment Agreement dated December 31, 2010 (filed as Exhibit 10.28 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.23	Pension Plan for Employees of SM Energy Company as Amended and Restated as of January 1, 2010 (filed as Exhibit 10.30 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.24+	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan as Amended as of November 9, 2010 (filed as Exhibit 10.31 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.25	Fourth Amended and Restated Credit Agreement dated May 27, 2011 among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.26	Gas Gathering Agreement dated May 31, 2011 between Regency Field Services LLC and SM Energy Company (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.27	Gathering and Natural Gas Services Agreement effective as of April 1, 2011 between SM Energy Company and ETC Texas Pipeline, Ltd. (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.28	Gas Processing Agreement effective as of April 1, 2011 between ETC Texas Pipeline, Ltd. and SM Energy Company (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.29†	Employee Stock Purchase Plan, As Amended and Restated as of June 10, 2011 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and

incorporated herein by reference)

10.30†	Form of Performance Stock Unit Award Agreement as of July 1, 2011 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.31†	Form of Restricted Stock Unit Award Agreement as of July 1, 2011 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.32†	Form of Performance Stock Unit Award Agreement as of September 6, 2011 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, and incorporated herein by reference)
10.33†	Form of Restricted Stock Unit Award Agreement as of September 6, 2011 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, and incorporated herein by reference)
10.34	Amendment No. 1 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2011 (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference)
10.35	Amendment No. 2 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2012 (filed as Exhibit 10.42 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference)
10.36†	Equity Incentive Compensation Plan, As Amended as of May 22, 2013 (filed as Annex A to the registrant's Schedule 14A filed on April 11, 2013, and incorporated herein by reference)
10.37	Fifth Amended and Restated Credit Agreement dated April 12, 2013, among SM Energy Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report of Form 8-K filed on April 15, 2013, and incorporated herein by reference)
10.38†	Form of Performance Stock Unit Award Agreement as of July 31, 2013 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, and incorporated herein by reference)
10.39†	Form of Restricted Stock Unit Award Agreement as of July 31, 2013 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, and incorporated herein by reference)
10.40†	SM Energy Company Non-Qualified Deferred Compensation Plan as of March 10, 2014 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 24, 2014, and incorporated herein by reference)
10.41*†	Cash Bonus Plan, As Amended and Restated as of February 1, 2014
10.42*†	Summary of Compensation Arrangements for Non-Employee Directors
12.1*	Computation of Ratio of Earnings to Fixed Charges
21.1*	Subsidiaries of Registrant
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Deloitte & Touche LLP
23.3*	Consent of Ryder Scott Company L.P.
24.1*	Power of Attorney
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Ryder Scott Audit Letter
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document

101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* Filed with this Form 10-K.

** Furnished with this Form 10-K.

*** Certain portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934.

†† Confidential Treatment has been requested with respect to portions of the exhibit. Such portions have been redacted and filed separately with the SEC.

† Exhibit constitutes a management contract or compensatory plan or agreement.

s Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on July 30, 2010 primarily to reflect the recent change in the name of the registrant from St. Mary Land & Exploration Company to SM Energy Company. There were no material changes to the substantive terms and conditions in this document.

\+ Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on November 9, 2010, in order to make technical revisions to ensure compliance with Section 409A of the Internal Revenue Code. There were no material changes to the substantive terms and conditions in this document.

(c) Financial Statement Schedules. See Item 15(a) above.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SM ENERGY COMPANY
(Registrant)

Date:	February 19, 2014	By:	/s/ ANTHONY J. BEST Anthony J. Best Chief Executive Officer (Principal Executive Officer)

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Anthony J. Best and A. Wade Pursell his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2013, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ ANTHONY J. BEST Anthony J. Best	Chief Executive Officer and Director (Principal Executive Officer)	February 19, 2014
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 19, 2014
/s/ MARK T. SOLOMON Mark T. Solomon	Vice President - Controller and Assistant Secretary (Principal Accounting Officer)	February 19, 2014

Signature	Title	Date
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Chairman of the Board of Directors	February 19, 2014
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 19, 2014
/s/ LARRY W. BICKLE Larry W. Bickle	Director	February 19, 2014
/s/ STEPHEN R. BRAND Stephen R. Brand	Director	February 19, 2014
/s/ WILLIAM J. GARDINER William J. Gardiner	Director	February 19, 2014
/s/ LOREN M. LEIKER Loren M. Leiker	Director	February 19, 2014
/s/ JULIO M. QUINTANA Julio M. Quintana	Director	February 19, 2014
/s/ JOHN M. SEIDL John M. Seidl	Director	February 19, 2014