SM Energy Co
Form 10-K
February 25, 2015

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, 2014
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
	Smaller reporting company o

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

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 66,163,202 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 30, 2014, the last business day of the registrant’s most recently completed second fiscal quarter, of $84.10 per share, as reported on the New York Stock Exchange; was $5,564,325,288. 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 18, 2015, the registrant had 67,463,060 shares of common stock outstanding.

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 2015 annual meeting of stockholders to be filed within 120 days after December 31, 2014.

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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 and condensate, natural gas, and natural gas liquids (also respectively referred to as "oil," "gas," and "NGLs," respectively, throughout the document) in onshore North America. 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 strategic objective is to build our ownership and operatorship of North American oil, gas, and NGL producing assets that have high operating margins and significant opportunities for additional economic investment. We pursue opportunities through both acquisitions and exploration, and seek to maximize the value of our assets through industry leading technology application and outstanding operational execution. We are returns focused and maintain a simple, strong balance sheet through a conservative approach to leverage.

Significant Developments in 2014

- Resource Play Delineation and Development Results in Record Production and Record Year-End Proved Reserve Estimates. Our estimated proved reserves increased 28 percent to 547.7 MMBOE at December 31, 2014, from 428.7 MMBOE at December 31, 2013. We added 143.9 MMBOE through drilling activities during the year, led by our efforts in our Eagle Ford shale play in south Texas and our Bakken/Three Forks play in North Dakota. Our proved reserve life increased to 9.9 years in 2014 compared to 8.9 years in 2013. We also achieved record levels of production in 2014. Our average daily production was composed of 45.6 MBbl of oil, 419.0 MMcf of gas, and 35.6 MBbl of NGLs for an average equivalent production rate of 151.1 MBOE per day, which was an increase of 14 percent from an average of 132.4 MBOE per day in 2013. Costs incurred for drilling and exploration activities, excluding acquisitions, increased 36 percent to $2.1 billion in 2014 when compared to 2013. Please refer to Core Operational Areas below for additional discussion concerning our 2014 estimated proved reserves, production, and capital investment.
- Acquisition Activity. During 2014, we acquired a total of 21.9 MMBOE of proved reserves through multiple transactions for consideration of approximately $544.6 million in cash plus approximately 7,000 net acres of non-core assets in our Rocky Mountain region. Through these acquisitions, we added approximately 74,000 net acres in our Gooseneck area in Divide County, North Dakota and approximately 38,000 net acres in our Powder River Basin program in Wyoming.
- Volatility and Decline in Commodity Prices. Our financial condition and results of operations are significantly affected by the prices we receive for oil, gas, and NGLs, which can fluctuate dramatically.

Oil prices drastically declined in late 2014. The daily NYMEX spot price ranged from a high of $107.62 per Bbl in July to a low of $53.27 per Bbl in December. Oil prices declined further subsequent to year end 2014, dropping to a low of $44.45 per Bbl in January 2015. The average NYMEX price decreased to $93.03 per Bbl in 2014 compared to $97.99 per Bbl in 2013.

Natural gas prices have been under downward pressure due to high levels of supply in recent years and were volatile during 2014. The daily NYMEX spot price improved early in 2014 with a high of $7.92 per MMBtu in March and then dropped significantly to a low of $2.75 per MMBtu in December. Gas prices declined further subsequent to year end 2014, dropping to a low of $2.55 per MMBtu in February 2015. The average NYMEX price increased in 2014 to $4.35 per MMBtu compared to $3.73 per MMBtu in 2013.

NGL prices decreased in 2014 in line with the steep decline in oil prices. The monthly OPIS NGL price reached a high of $48.43 per Bbl in February and a low of $22.44 per Bbl in December. NGL prices declined further subsequent to year end 2014, dropping to a low of $20.03 per Bbl in January 2015. The average OPIS price decreased in 2014 to $38.93 per Bbl compared to $40.44 per Bbl in 2013.

- Impairments. We recorded impairment of proved properties expense of $84.5 million and abandonment and impairment of unproved properties expense of $75.6 million for the year ended December 31, 2014. Impairments recorded in 2014 were a result of the significant decline in commodity prices in late 2014 and recognition of the outcomes of exploration and delineation wells in certain prospects in our South Texas & Gulf Coast and Permian regions.

Outlook for 2015

We view 2015 as a year of transition as the broader oil and gas industry adjusts to lower oil prices. Exploration and production companies are reducing drilling and completion activity, which we expect to result in service companies lowering the price of their services. Our plan for 2015 is to scale down activity over the course of the year while preserving the value of our assets and protecting the strength of our balance sheet. Our goal is to be well positioned entering 2016 in what we expect will be a stronger commodity price and lower service cost environment, while having the strength and flexibility to adapt should industry conditions worsen.

Our capital program for 2015 will be approximately $1.2 billion, of which approximately $1.0 billion will be invested in drilling and completion activities. We expect to focus 85 percent of our drilling and completion capital on our core development programs in the Eagle Ford shale and the Bakken/Three Forks formations. The remaining capital is being allocated to the construction of facilities, leasehold acquisitions, exploration overhead, and geological and geophysical costs. Please refer to Outlook for 2015 under Part II, Item 7 of this report for additional discussion concerning our capital plans for 2015.

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, production, and costs incurred in oil and gas activities for the year ended December 31, 2014, for our core operating areas:

	South Texas & Gulf Coast		Rocky Mountain		Permian		Mid-Continent		Total (1)	
Proved Reserves										
Oil (MMBbl)	64.5		91.5		13.5		0.2		169.7	
Gas (Bcf)	1,193.3		89.6		38.9		144.8		1,466.5	
NGLs (MMBbl)	131.2		2.0		—		0.4		133.5	
MMBOE (1)	394.6		108.4		20.0		24.7		547.7	
Relative percentage	72	%	20	%	4	%	4	%	100	%
Proved Developed %	48	%	56	%	76	%	83	%	52	%
PV-10 (in millions) (2)										
Proved Developed	$2,942.8		$1,651.5		$440.8		$217.9		$5,253.0	
Proved Undeveloped	1,593.0		699.0		55.5		16.4		2,363.9	
Total Proved	$4,535.8		$2,350.5		$496.3		$234.3		$7,616.9	
Relative percentage	60	%	31	%	6	%	3	%	100	%
Production										
Oil (MMBbl)	7.1		7.4		2.0		0.1		16.7	
Gas (Bcf)	121.6		7.0		4.5		19.8		152.9	
NGLs (MMBbl)	12.8		0.1		—		0.1		13.0	
MMBOE (1)	40.2		8.7		2.8		3.5		55.1	
Avg. Daily Equivalents (MBOE/d)	110.1		23.9		7.6		9.5		151.1	
Relative percentage	73	%	16	%	5	%	6	%	100	%
Costs Incurred (in millions)(3)	$1,187.8		$1,241.8		$195.4		$58.9		$2,711.7	

(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 in Part II, Item 8 of this report. A reconciliation between PV-10 and the after tax amount 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. Within this region, we have both operated and non-operated Eagle Ford shale programs on approximately 180,000 net acres. Our operated program accounts for approximately 75 percent of our total Eagle Ford acreage and production. Our acreage position covers a significant portion of the western Eagle Ford shale play, including acreage in the oil/condensate, NGL-rich gas, and dry gas windows of the play.

In addition, we continued to evaluate an emerging new venture play in east Texas in 2014. We have approximately 215,000 net acres that provide opportunities in the Austin Chalk, Woodbine, and Eagle Ford shale intervals. During 2014, we constructed a gathering system to allow for longer-term production tests on our wells.

We deployed a significant amount of capital in our South Texas & Gulf Coast region in 2014 in our operated and outside-operated Eagle Ford shale programs. Costs incurred increased to $1.2 billion in 2014 from $849.4 million in 2013. Estimated proved reserves at year-end 2014 increased 27 percent from 311.2 MMBOE at year-end 2013. We added approximately 105.8 MMBOE of estimated proved reserves through drilling activities. During 2012, 2013, and early 2014, 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"). The remainder of our carry was expended during the first and second quarters of 2014, at which point we began accruing and funding our share of previously carried drilling and completion costs. Please refer to Note 12 - Acquisition and Development Agreement in Part II, Item 8 for additional discussion. Production in 2014 increased 30 percent from the 30.9 MMBOE produced in 2013.

Rocky Mountain Region. Operations in our Rocky Mountain region are managed from our office in Billings, Montana. Our 2014 activity in this region focused on the development and growth through acquisition of assets targeting the Bakken/Three Forks formations, primarily in Williams, McKenzie, and Divide Counties of North Dakota, and on the expansion and delineation of our Powder River Basin program in Wyoming. In the Williston Basin, we have approximately 245,000 net acres, of which approximately 160,000 net acres are being actively developed in the Bakken and Three Forks formations. In the Powder River Basin, we have approximately 175,000 net acres, a large portion of which are prospective for the Frontier and Shannon intervals.

Costs incurred in our Rocky Mountain region increased from $474.7 million in 2013 to $1.2 billion in 2014, largely as a result of our Williston Basin and Powder River Basin proved and unproved property acquisitions totaling $561.6 million in 2014. This amount includes the fair value of properties acquired in an asset exchange and the estimated asset retirement obligations associated with the acquired producing properties. Estimated proved reserves for the region at the end of 2014 increased 43 percent from 76.0 MMBOE at year-end 2013. During the year, we added approximately 25.3 MMBOE of proved reserves in this region through drilling activities and approximately 21.9 MMBOE through acquisitions. Production for 2014 increased 18 percent from 7.4 MMBOE produced in 2013.

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. Our 2014 activity focused on the testing of shale potential and development of our assets in the Midland Basin. As of December 31, 2014, we had approximately 113,000 net acres in our Permian region.

Costs incurred in our Permian region decreased to $195.4 million in 2014 compared to $275.7 million in 2013. Estimated proved reserves increased 22 percent from 2013 year-end proved reserves of 16.3 MMBOE. Production increased 16 percent from 2.4 MMBOE produced in 2013.

Mid-Continent Region. Our Mid-Continent region is managed from our office in Tulsa, Oklahoma, and consists of our Haynesville and Woodford Shale assets.

Costs incurred in our Mid-Continent region decreased to $58.9 million in 2014 compared to $91.9 million incurred in 2013. Estimated proved reserves decreased two percent from 2013 year-end proved reserves of 25.2 MMBOE. Production decreased 55 percent from 7.7 MMBOE produced in 2013, primarily as a result of the divestiture of our Anadarko Basin assets in December 2013.

Subsequent to December 31, 2014, we announced plans to close our regional office in Tulsa, Oklahoma and market our remaining assets located in the Arkoma Basin of Oklahoma and Arklatex area of east Texas and northern Louisiana.

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, 2014. We engaged Ryder Scott Company, L.P. (“Ryder Scott”) to audit at least 80 percent of our total calculated proved reserve PV-10 for each year presented. The prices used in the calculation of proved reserve estimates reflect the 12 month average of the first-day-of-the-month prices in accordance with Securities and Exchange Commission (“SEC”) rules, and were $94.99 per Bbl for oil, $4.35 per MMBtu for natural gas, and $39.91 per Bbl for NGLs for the year ended December 31, 2014. We then adjust these prices to reflect appropriate basis, quality, and location differentials over the period in estimating our proved reserves.

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. PV-10 shown in the following table is not intended to represent the current market value of our estimated proved reserves. The actual quantities and present value of our estimated proved reserves may be more or 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 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 below.

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 well as reserve metrics presented in this report, are widely understood by those who make investment decisions related to the oil and gas exploration and production business.

The following table summarizes estimated proved reserves, PV-10, standardized measure of discounted future cash flows, and reserve replacement as of December 31, 2014, 2013, and 2012:

	As of December 31,		
	2014	2013	2012
Reserve data:			
Proved developed			
Oil (MMBbl)	89.3	70.2	58.8
Gas (Bcf)	784.6	569.2	483.2
NGLs (MMBbl)	66.7	43.8	27.2
MMBOE (1)	286.8	208.9	166.5
Proved undeveloped			
Oil (MMBbl)	80.4	56.3	33.5
Gas (Bcf)	682.0	620.1	350.2
NGLs (MMBbl)	66.8	60.2	35.1
MMBOE (1)	260.9	219.9	126.9
Total Proved (1)			
Oil (MMBbl) (1)	169.7	126.6	92.2
Gas (Bcf) (1)	1,466.5	1,189.3	833.4
NGLs (MMBbl) (1)	133.5	103.9	62.3
MMBOE (1)	547.7	428.7	293.4
Proved developed reserves %	52 %	49 %	57 %
Proved undeveloped reserves %	48 %	51 %	43 %
Reserve data (in millions):			
Proved developed PV-10	$5,253.0	$3,898.6	$2,982.6
Proved undeveloped PV-10	2,363.9	1,629.9	866.5
Total proved PV-10	$7,616.9	$5,528.5	$3,849.1
Standardized measure of discounted future cash flows	$5,698.8	$4,009.4	$3,021.0
Reserve replacement – drilling, excluding revisions	261 %	405 %	411 %
All in – including sales of reserves	316 %	380 %	329 %
All in – excluding sales of reserves	320 %	418 %	337 %
Reserve life (years)	9.9	8.9	8.0

(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 pre-tax PV-10 (Non-GAAP) of total proved reserves. Please see the definitions of standardized measure of discounted future net cash flows and PV-10 in the Glossary of Oil and Gas Terms section of this report below.

	As of December 31,		
	2014	2013	2012
	(in millions)		
Standardized measure of discounted future net cash flows	$5,698.8	$4,009.4	$3,021.0
Add: 10 percent annual discount, net of income taxes	3,407.2	2,500.6	1,742.1
Add: future undiscounted income taxes	3,511.4	2,722.2	1,609.4
Undiscounted future net cash flows	12,617.4	9,232.2	6,372.5
Less: 10 percent annual discount without tax effect	(5,000.5)	(3,703.7)	