Sanchez Energy Corp
Form 10-K
March 02, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ý **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: 1-35372

Sanchez Energy Corporation

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**45-3090102** (I.R.S. Employer Identification No.)
1000 Main Street, Suite 3000 **Houston, Texas** (Address of principal executive offices)	**77002** (Zip Code)

(713) 783-8000
(Registrant's telephone number, including area code)

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

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. ý

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 ý	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 ý

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2014: $1,967,667,119

Number of shares of registrant's common stock outstanding as of February 26, 2015: 61,085,570.

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2015 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2014, are incorporated by reference into Part III of this report for the year ended December 31, 2014.

Table of Contents

We were previously considered an "emerging growth company" as defined under the Jumpstart Our Business Startups Act of 2012, commonly referred to as the "JOBS Act." The JOBS Act permits a company to be classified as an "emerging growth company" for up to five years from the date of the completion of its initial public offering ("IPO") or until the earlier of (1) the last day of the fiscal year in which its total annual gross revenues exceed $1 billion, (2) the date that it becomes a "large accelerated filer" as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), which would occur if the market value of its common equity that is held by non-affiliates is $700 million or more as of the last business day of its most recently completed second fiscal quarter or (3) the date on which it has issued more than $1 billion in non-convertible debt during the preceding three year period. During the second quarter of 2014, Sanchez Energy Corporation issued non-convertible debt in an amount such that we have now issued more than $1 billion in non-convertible debt during the preceding three year period. As such, we are no longer considered an "emerging growth company" under the JOBS Act.

Further, as of June 30, 2014, the market value of our common equity held by non-affiliates was greater than $700 million. As such, Sanchez Energy Corporation became a large accelerated filer as defined in Rule 12b-2 under the Exchange Act on December 31, 2014.

SANCHEZ ENERGY CORPORATION
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2014

Table of Contents

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains "forward-looking statements" within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Annual Report on Form 10-K that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These statements are based on certain assumptions we made based on management's experience, perception of historical trends and technical analyses, current conditions, anticipated future developments and other factors believed to be appropriate and reasonable by management. When used in this Annual Report on Form 10-K, words such as "will," "potential," "believe," "estimate," "intend," "expect," "may," "should," "anticipate," "could," "plan," "predict," "project," "profile," "model," "strategy," "future" or their negatives or the statements that include these words or other words that convey the uncertainty of future events or outcomes, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, statements, express or implied, concerning our future operating results and returns or our ability to replace or increase reserves, increase production, or generate income or cash flows are forward-looking statements. Forward-looking statements are not guarantees of performance. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond our control. Although we believe that the expectations reflected in our forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Important factors that could cause our actual results to differ materially from the expectations reflected in the forward-looking statements include, among others:

- our ability to successfully execute our business and financial strategies;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- the timing and extent of changes in prices for, and demand for, crude oil and condensate, natural gas liquids ("NGLs"), natural gas and related commodities;
- the realized benefits of the acreage acquired in our various acquisitions and other assets and liabilities assumed in connection therewith;
- the extent to which our drilling plans are successful in economically developing our acreage in, and to produce reserves and achieve anticipated production levels from, our existing and future projects;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- the extent to which we can optimize reserve recovery and economically develop our plays utilizing horizontal and vertical drilling, advanced completion technologies and hydraulic fracturing;
- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;
- competition in the oil and natural gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;

the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;

Table of Contents

- our ability to compete with other companies in the oil and natural gas industry;

- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;

- developments in oil-producing and natural gas-producing countries, the actions of the Organization of Petroleum Exporting Countries ("OPEC") and other factors affecting the supply of oil and natural gas;

- our ability to effectively integrate acquired crude oil and natural gas properties into our operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;

- the extent to which our crude oil and natural gas properties operated by others are operated successfully and economically;

- the use of competing energy sources and the development of alternative energy sources;

- unexpected results of litigation filed against us;

- the extent to which we incur uninsured losses and liabilities or losses and liabilities in excess of our insurance coverage; and

- the other factors described under "Item 1A. Risk Factors" in this Annual Report on Form 10-K and any updates to those factors set forth in our subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by our forward-looking statements may not occur, and, if any of such events do, we may not have correctly anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of our forward-looking statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Table of Contents

PART I

Item 1. *Business*

Overview

Sanchez Energy Corporation (together with our consolidated subsidiaries, the "Company," "we," "our," "us" or similar terms), a Delaware corporation formed in August 2011, is an independent exploration and production company focused on the exploration, acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the Eagle Ford Shale in South Texas and, to a lesser extent, the Tuscaloosa Marine Shale ("TMS") in Mississippi and Louisiana. We have accumulated approximately 226,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale and approximately 69,000 net leasehold acres in what we believe to be the core of the TMS. We are currently focused on the horizontal development of significant resource potential from the Eagle Ford Shale, with plans to invest approximately 93% of our total 2015 drilling and completion capital budget in this area. We are continuously evaluating opportunities to grow both our acreage and our producing assets through acquisitions. Our successful acquisition of such assets will depend on both the opportunities and the financing alternatives available to us at the time we consider such opportunities. We have included definitions of some of the oil and natural gas terms used in this Annual Report on Form 10-K in the "Glossary of Selected Oil and Natural Gas Terms."

On June 30, 2014, we completed our acquisition of 106,000 net contiguous acres in Dimmit, LaSalle and Webb Counties, Texas with 176 gross producing wells (the "Catarina acquisition") in the Eagle Ford Shale with an effective date of January 1, 2014. Including the approximate $51 million deposit paid prior to closing, total consideration for the acquisition was approximately $557 million, comprised of the $639 million purchase price less approximately $82 million in normal and customary closing adjustments. The purchase price is subject to customary post-closing adjustments. Proved reserves as of the effective date were estimated to be approximately 60 mmboe and were 57 mmboe as of June 30, 2014 as a result of normal declines. The reserves that were produced were not replaced from the effective time to the closing date due to the substantial decrease in drilling and completion activity by the seller. Production during the time period from effective date to closing averaged approximately 22,200 boe/d.

All proved reserves in the Catarina area are covered under lease acreage that is held by production, which acreage amounted to approximately 29,000 acres. Under the lease we have a 100% working interest and 75% net revenue interest in the lease acreage over the Eagle Ford Shale formation from the top of the Austin Chalk formation to the base of the Buda Lime formation. Each producing horizontal well that is not in an existing unit already held by production holds 320 acres by its production. The 77,000 acres of undeveloped acreage that were included in the Catarina acquisition are subject to a continuous drilling obligation. Such drilling obligation requires us to drill (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120-day period in order to maintain rights to any future undeveloped acreage. Up to 30 wells drilled in excess of the minimum 50 wells in a given annual period can be carried over to satisfy part of the 50 well requirement in the subsequent annual period on a well for well basis. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include the drilling of at least the minimum number of wells required to maintain access to such undeveloped acreage.

On October 4, 2013, we completed our acquisition of 3,600 net contiguous acres of leasehold in McMullen County, Texas with 13 gross producing wells (the "Wycross acquisition") in the Eagle Ford Shale. At the effective date of July 1, 2013 this acquisition added approximately 11 mmboe of net proved reserves and 2,000 boe/d of production. The properties acquired in the Wycross acquisition are included in our Cotulla area described below.

Table of Contents

On August 16, 2013, we completed an asset acquisition of approximately 40,000 net undeveloped acres in the TMS (the "TMS transaction") in Southwest Mississippi and Southeast Louisiana and the formation of an area of mutual interest ("AMI") and a 50/50 joint venture with SR Acquisition I, LLC ("SR"), a subsidiary of our affiliate Sanchez Resources, LLC ("Sanchez Resources"). As of December 31, 2014, the AMI held rights to approximately 150,000 gross and 108,000 net acres in what we believe to be the core of the TMS, of which we owned approximately 69,000 net acres.

In July 2013, we acquired approximately 10,300 net acres and approximately 250 boe/d of estimated production in Fayette, Gonzales and Lavaca Counties, Texas with 7 gross producing wells (the "Five Mile Creek acquisition") for approximately $29 million. The properties acquired in the Five Mile Creek acquisition are included in our Marquis area, and are directly to the northwest of our Prost development project.

On May 31, 2013, we completed our acquisition of 44,461 net acres in Dimmit, Frio, LaSalle and Zavala Counties, Texas with 53 gross producing wells (the "Cotulla acquisition"). The acquisition included estimated proved reserves as of March 31, 2013 of 14.2 mmboe, 66% oil, 13% NGLs and 21% natural gas, with proved developed reserves estimated to account for approximately 48% of total proved reserves. We combined our new Cotulla assets with our previous Maverick area to form one operating area now known as our Cotulla area. As noted above, the Cotulla area also includes the properties acquired in the Wycross acquisition.

Our 2015 capital budget of $600 - $650 million is allocated approximately 93% to the drilling of 75 net wells and completion of 88 net wells with the remainder allocated to facilities, leasing, and seismic activities.

For 2015, our operating plans largely focus on continued improvement to our manufacturing efficiency with the goal of steady improvement in our capital efficiency in order to preserve liquidity and financial flexibility. Our 2015 capital budget will be focused on the development of our approximately 226,000 net acres in the Eagle Ford Shale. In the Eagle Ford, we plan on investing $525 - $555 million, or approximately 93%, of our drilling and completion budget to spud 73 net wells and complete 86 net wells in 2015. In addition, we intend to invest $35 - $45 million on drilling and completing up to 3 gross (1.5 net) wells in the TMS.

The following table presents summary data for our Eagle Ford and TMS project areas as of December 31, 2014 as well as our capital expenditure budget for the 2015 fiscal year:

				Identified Drilling Locations(2)		2015 Capital Expenditure Budget				
	Net Acreage	Average Working Interest(1)	Operator	Gross	Net	Net Wells Spud	Net Wells Completed	Drilling & Completion ("D&C") Capital (in millions)	% of Operating Capital	% of D&C Capital
Catarina	106,070	100%	Sanchez Energy	1,585	1,585	58	65	$400 - $410	65%	70%
Marquis	72,394	100%	Sanchez Energy	900	900	1	3	$15 - $20	3%	3%
Cotulla	38,925	85%	Sanchez Energy	705	670	3	7	$30 - $40	6%	6%
Palmetto	8,861	48%	Marathon	355	170	11	11	$80 - $85	13%	14%
Total Eagle Ford	226,250	93%		3,545	3,325	73	86	$525 - $555	86%	93%
TMS	68,760	64%	Sanchez Oil and Gas	345	220	2	2	$35 - $45	6%	7%
Total D&C Capital Budget	295,010	84%		3,890	3,545	75	88	$560 - $600	93%	100%
Factilities, Leasing and Seismic								$40 - $50	7%	
Total Capital Budget								$600 - $650	100%	

(1) Average working interests reflect the Company's average working interests in the leases it holds.

(2) Using approximately 40 acre well-spacing for our Cotulla and Palmetto areas, approximately 60 acre well-spacing for our Marquis area, and approximately 75 acre well-spacing for our Catarina area plus up to 650 additional upper Eagle Ford Catarina locations, and assuming 80% of the acreage is drillable for Cotulla, Marquis and Catarina, and 90% of the acreage is drillable for Palmetto, we believe that there could be over 3,500 potential gross (3,300 net) locations for potential future drilling in the Eagle Ford. Using approximately 250 acre well-spacing for our TMS area and assuming 80% of the acreage is drillable, we believe that there are up to 345 gross (220 net) locations for potential future drilling. In total, we believe that there are over 3,800 potential gross (3,500 net) Eagle Ford and TMS locations for future drilling.

Table of Contents

Our Business Strategies

Our primary business objective is to increase reserves, production and cash flows at an attractive return on invested capital. Our business strategy is currently focused on exploiting long-life, unconventional oil, condensate, NGL and natural gas reserves from the Eagle Ford Shale and the TMS. Key elements of our business strategy include:

Efficiently develop our Eagle Ford Shale leasehold positions. We intend to efficiently drill and develop our acreage position to maximize the value of our resource potential. At December 31, 2014, approximately 52% of our proved reserves were proved undeveloped. As of December 31, 2014, we were producing from 485 wells and have identified over 3,300 net locations for potential future drilling in our Eagle Ford Shale area that will be our primary targets in the near term. In 2015, we plan to invest between $525 and $555 million on development drilling and completion in the Eagle Ford Shale to spud 73 net wells and complete approximately 86 net wells. This represents approximately 93% of our 2015 drilling and completion budget and 87% of our total 2015 capital budget.

Enhance returns by focusing on operational and cost efficiencies. We are focused on continuous improvement of our operating measures and have significant experience in successfully converting early-stage resource opportunities into cost-efficient development projects. We believe the magnitude and concentration of our acreage within our core project areas provide us with the opportunity to capture economies of scale, including the ability to drill multiple wells from a single drilling pad, utilizing centralized production and fluid handling facilities and reducing the time and cost of rig mobilization.

Adopt and employ leading drilling and completion techniques. We are focused on enhancing our drilling and completion techniques to maximize recovery of reserves. Industry techniques with respect to drilling and completion have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of longer laterals and more tightly spaced fracture stimulation stages. We continuously evaluate industry drilling results and monitor the results of other operators to improve our operating practices, and we expect our drilling and completion techniques will continue to evolve.

Leverage our relationship with our affiliates to expand unconventional oil, condensate, NGL and natural gas assets. Sanchez Oil & Gas Corporation ("SOG"), headquartered in Houston, Texas, is a private full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. The Company refers to SOG, Sanchez Energy Partners I, LP, and their affiliates (but excluding the Company), collectively, as the "Sanchez Group." Various members of the Sanchez Group have drilled or participated in over 1,100 wells, directly and through joint ventures, and have invested substantial amounts of capital in the oil and natural gas industry since 1972. During this period, they have carefully cultivated relationships with mineral and surface rights owners in and around our Eagle Ford and TMS areas and compiled an extensive technological database which we believe gives us a competitive advantage in acquiring additional leasehold positions in these areas. We have unrestricted access to the proprietary portions of the technological database related to our properties and SOG is otherwise required to interpret and use the database for our benefit. We plan to leverage our affiliates' expertise, industry relationships and size to opportunistically expand reserves and our leasehold positions in the Eagle Ford Shale and other onshore unconventional oil, condensate, NGL and natural gas resources. The strength of these relationships is evidenced by the TMS transaction, where our working interest partner is another member of the Sanchez Group.

Table of Contents

Pursue strategic acquisitions to grow our leasehold position in the Eagle Ford Shale and seek entry into new basins. We believe that we will be able to identify and acquire additional acreage and producing assets in the Eagle Ford Shale at attractive valuations by leveraging our longstanding relationships in and knowledge of South Texas. We also plan to selectively target additional domestic basins that would allow us to employ our strategies on attractive acreage positions that we believe are similar to our Eagle Ford Shale acreage. Our 2013 TMS transaction was consistent with this strategy and gave us approximately 40,000 net acres, currently 69,000 net acres, within what we believe to be the core of the TMS.

Maintain substantial financial liquidity and flexibility. As of December 31, 2014, we had approximately $474 million of cash and cash equivalents and a $650 million unused, available borrowing base (with a $300 million elected commitment amount) under our Second Amended and Restated Credit Agreement (defined in Note 5, "Long-Term Debt"). We believe that this strong liquidity position combined with our cash flow from operations will allow us to continue executing a capital expenditure program that should result in steady growth of production, cash flow and proved reserves. The Company does not expect that any potential future changes to our borrowing base would impact our elected commitment amount. Furthermore, we have entered into and intend to continue executing hedging transactions for a significant portion of our expected production to achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in oil and natural gas prices.

Our Competitive Strengths

We believe the following competitive strengths will allow us to successfully execute our business strategies:

Geographically concentrated leasehold position in leading North American unconventional oil resource trends. We have assembled a current leasehold position of approximately 226,000 net acres in the Eagle Ford Shale, which we believe to be one of the highest rates of return unconventional oil and natural gas formations in North America. In addition to further leveraging our base of technical expertise in our project areas, our geographically concentrated acreage position allows us to establish economies of scale with respect to drilling, production, operating and administrative costs in addition to further leveraging our base of technical expertise in our project areas. We believe that our recent well results and offset operator activity in and around our project areas have significantly de-risked our acreage position such that there are low geologic risks and ample repeatable drilling opportunities across our core operating areas. In addition to our Eagle Ford Shale acreage, we have approximately 69,000 net acres in what we believe to be the core of the TMS. Recent well results by other operators in the area are encouraging with respect to both strong well performance and decreasing drilling and completion costs, which we believe will be enhanced by continued delineation and development drilling in the TMS during 2015 by us and other operators in the basin. We plan to allocate approximately 7% of our 2015 drilling and completion budget and 6% of our total 2015 capital budget to this area.

Demonstrated ability to drive oil production and reserves growth. Our average production for the fourth quarter of 2014 was 43,897 boe/d, substantially all of which was from the Eagle Ford Shale. This compares to approximately 38,613 boe/d in the third quarter of 2014 and 18,810 boe/d during the fourth quarter of 2013. Our total proved reserves at December 31, 2014 was 134.8 mboe, a growth of 129% over the same period a year ago.

Large oil-weighted multi-year drilling inventory. We have an inventory of over 3,300 net locations for potential future drilling on our acreage position in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale based on spacing varying from 75 acres to 40 acres. In 2015, we plan to spud approximately 73 net wells and complete approximately 86 net wells on our existing Eagle Ford Shale acreage. We have an inventory of up to 220 net oil weighted locations in our TMS area. Our knowledge about the basin's potential will be enhanced by continued delineation and development drilling in the TMS by us and other operators.

Experienced management and strong technical team. Our team is comprised of individuals with a long history in the oil and natural gas business, and a number of our key executives have prior experience as members of public company management teams. Furthermore, members of the Sanchez Group have a 40-plus year operating history in the basins in which we operate, providing us with extensive knowledge of the basins and the ability to leverage longstanding relationships with mineral owners. Through SOG we have access to an experienced staff of oil and natural gas professionals including geophysicists, geologists, drilling and completion engineers, production and reservoir engineers and technical support staff. This technical team is large enough to support our growth into a significantly larger company relative to our current size. SOG's technical team has significant experience and expertise in applying the most sophisticated technologies used in conventional and unconventional resource style plays including 3-D seismic interpretation capabilities, horizontal drilling, comprehensive multi-stage hydraulic fracture stimulation programs and other exploration, production and processing technologies. We believe this technical expertise is integral to successful exploitation of our assets, including defining new core producing areas in emerging plays.

Core Properties

Eagle Ford Shale

We and our predecessor entities have a long history in the Eagle Ford Shale, where we have assembled approximately 226,000 net leasehold acres with an average working interest of approximately 93%. Using approximately 40 acre well-spacing for our Cotulla and Palmetto areas, approximately 60 acre well-spacing for our Marquis area, and approximately 75 acre well-spacing for our Catarina area plus up to 650 additional upper Eagle Ford Catarina locations, and assuming 80% of the acreage is drillable for Cotulla, Marquis and Catarina, and 90% of the acreage is drillable for Palmetto, we believe that there could be over 3,500 potential gross (3,300 net) locations for potential future drilling. Consistent with other operators in this area, we perform multi-stage hydraulic fracturing up to 30 stages on each well depending upon the length of the lateral section. For the year 2015, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

In our Catarina area, we have approximately 106,000 net acres in Dimmit, LaSalle and Webb Counties, Texas with a 100% working interest. We have brought online 11 upper Eagle Ford wells and 6 lower Eagle Ford wells with combined average 30 day production rates of approximately 1,350 boe/d. For the year 2015, we plan to spend $400 - $410 million to spud 58 and complete 65 net wells in our Catarina area.

In our Marquis area, we have approximately 72,000 net acres, the majority of which are in southwest Fayette and northeast Lavaca Counties, Texas with a 100% working interest. We believe that our Marquis acreage lies in the volatile oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $6 million and $11 million per well based on our historical well costs. We have drilled 45 horizontal wells in our Prost area of Marquis that had average 30 day production rates of approximately 650 boe/d. We have drilled 6 horizontal wells in our Five Mile Creek area of Marquis that had average 30 day production rates of approximately 500 boe/d. We have identified up to 900 gross and net locations based on 60 acre well-spacing for potential future drilling on our Marquis acreage. For the year 2015, we plan to spend $15 - $20 million to spud one net well and complete three net wells in our Marquis area.

In our Cotulla area, we have approximately 39,000 net acres in Dimmit, Frio, LaSalle, Zavala, and McMullen Counties, Texas with an average working interest of approximately 85%. We believe that our Cotulla acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $5.5 million and $9.0 million per well based on our historical well costs. Our primary focus in our Cotulla area are our Alexander Ranch and Wycross development projects. In our Alexander Ranch development project, 45 wells have been brought online with average 30 day production rates of approximately 500 boe/d. In our Wycross development project, 30 wells have been brought online with average 30 day production rates of approximately 700 boe/d. We have identified up to 705 gross (670 net) locations based on 40 acre well-spacing for potential future drilling on our Cotulla area. For the year 2015, we plan to spend $30 - $40 million to spud three net wells and complete seven net wells in our Cotulla area.

In our Palmetto area, we have approximately 9,000 net acres in Gonzales County, Texas with an average working interest of approximately 48%. We believe that our Palmetto acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $7 million and $11 million per well based on our historical well costs. We have participated in the drilling of 62 gross wells on our acreage that had an average 30 day production rate of approximately 900 boe/d. We have identified up to 355 gross (170 net) locations based on 40 acre well-spacing for potential future drilling in our Palmetto area. For the year 2015, we plan to spend $80 - $85 million to spud and complete 11 net wells in our Palmetto area.

Tuscaloosa Marine Shale

In August 2013, we acquired approximately 40,000 net undeveloped acres in what we believe to be the core of the TMS for cash and shares of our common stock. In connection with the TMS transaction, we established an AMI in the TMS with SR, which transaction included a carry on drilling costs for up to 6 gross (3 net) wells. As part of the transaction, we acquired all of the working interests in the AMI owned at closing from three sellers (two third parties and one related party of the Company, SR), resulting in our owning an undivided 50% working interest across the AMI through the TMS formation. As of December 31, 2014 the AMI held rights to approximately 150,000 gross (108,000 net) acres, of which we owned approximately 69,000 net acres.

Total consideration for the transactions consisted of approximately $70 million in cash and the issuance of 342,760 common shares of the Company, valued at approximately $7.5 million. The total cash consideration provided to SR, an affiliate of the Company, was $14.4 million, before consideration of any well carries. The acquisitions were accounted for as the purchase of assets at cost at the acquisition date.

We have also committed, as a part of the total consideration, to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI. In the event that we did not fulfill in a timely manner our obligations with regard to the initial TMS well commitment we would have re-assigned the working interests acquired from SR. As of the date of this filing, we have met our initial well carry and exercised our right to continue drilling within the AMI and earn full rights to all acreage by carrying SR for an additional 3 gross (1.5 net) TMS wells. We expect to meet our well carry commitments for the full 6 gross (3 net) TMS wells in 2015.

Recent well results by other operators in the area are encouraging with respect to both strong well performance and decreasing drilling and completion costs. We plan to allocate approximately 6% of our total 2015 capital budget to our TMS area. The average remaining lease term on the acreage is over 3 years, giving us ample time to allow other industry participants to further de-risk the play.

Table of Contents

Oil and Natural Gas Reserves and Production

Internal Controls

Our estimated reserves at December 31, 2014 were prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers. We expect to continue to have our reserve estimates prepared semi-annually by our independent third-party reserve engineers. Our internal professional staff works closely with Ryder Scott to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, we provide Ryder Scott other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their evaluation of our reserves.

Technology Used to Establish Reserves

Under the rules of the Securities and Exchange Commission (the "SEC"), proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, Ryder Scott employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

Qualifications of Responsible Technical Persons

Internal SOG Engineers. Vinodh Kumar is the technical person primarily responsible for overseeing the preparation of our reserve estimates. Mr. Kumar has over 40 years of industry experience with positions of increasing responsibility in engineering and evaluations with companies such as Hilcorp Energy Company, El Paso Exploration & Production Company, KCS Energy, Inc. and Koch Industries, Inc. He holds a Masters of Science degree in Petroleum Engineering from the University of Calgary and a Masters of Business Administration from Wichita State University. Mr. Kumar is a Registered Professional Engineer in the State of Texas.

Independent Reserve Engineers. Ryder Scott is an independent oil and natural gas consulting firm. No director, officer or key employee of Ryder Scott has any financial ownership in any member of the Sanchez Group or us. Ryder Scott's compensation for the required investigations and preparation of its

Table of Contents

report is not contingent upon the results obtained and reported, and Ryder Scott has not performed other work for SOG, Sanchez Energy Partners I, LP ("SEP I") or us that would affect its objectivity. The engineering information presented in Ryder Scott's report was overseen by Don P. Griffin, P.E. Mr. Griffin is an experienced reservoir engineer having been a practicing petroleum engineer since 1976. He has more than 30 years of experience in reserves evaluation with Ryder Scott. He has a Bachelor of Science degree in Electrical Engineering from Texas Tech University. Mr. Griffin is a Registered Professional Engineer in the State of Texas.

Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to our properties and the standardized measure amounts associated with the estimated proved reserves attributable to our properties as of December 31, 2014, based on a reserve report prepared by Ryder

Table of Contents

Scott, our independent reserve engineers. The standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

	As of December 31, 2014				
	Oil (mmbo)	Natural Gas Liquids (mmbbl)	Natural Gas (bcf)	Total Estimated Proved Reserves (mmboe)(2)	PV-10 (in millions)
Reserve Data(1):					
Estimated proved reserves by project area:					
Eagle Ford					
Catarina	14.8	27.6	165.8	70.1	$ 593.1
Marquis	13.5	1.6	6.4	16.2	346.5
Cotulla	18.0	2.9	18.2	23.9	502.4
Palmetto	17.8	3.2	19.3	24.2	462.4
Total Eagle Ford	64.1	35.3	209.7	134.4	1,904.4
TMS	0.4			0.4	18.9
Total	64.5	35.3	209.7	134.8	$ 1,923.3
Standardized Measure (in millions)(1)(3)					$ 1,780.5
Estimated proved developed reserves by project area:					
Eagle Ford					
Catarina	7.8	14.8	89.0	37.5	$ 556.1
Marquis	6.8	0.9	3.6	8.3	303.7
Cotulla	7.5	1.7	11.2	11.1	310.7
Palmetto	4.9	1.2	6.8	7.2	221.9
Total Eagle Ford	27.0	18.6	110.6	64.1	1,392.4
TMS	0.4			0.4	18.9
Total	27.4	18.6	110.6	64.5	$ 1,411.3
Estimated proved undeveloped reserves by project area:					
Eagle Ford					
Catarina	7.0	12.8	76.8	32.6	$ 37.0
Marquis	6.7	0.7	2.8	7.9	42.8
Cotulla	10.5	1.2	7.0	12.8	191.7
Palmetto	12.9	2.0	12.5	17.0	240.5
Total Eagle Ford	37.1	16.7	99.1	70.3	512.0
TMS					
Total	37.1	16.7	99.1	70.3	$ 512.0

(1) Our estimated net proved reserves and related standardized measure were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of our properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $94.99/bo for oil, $44.84/bbl for NGLs and $4.35/mmbtu for natural gas at December 31, 2014. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price realized at the wellhead. For the year ended December 31, 2014,

Table of Contents

the average realized prices for oil, NGLs and natural gas were $88.64 per bo, $25.86 per bbl and $4.06 per mcf, respectively. For a description of our commodity derivative contracts, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Costs and Operating Expenses Commodity Derivative Transactions" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Derivative Instruments."

(2) One boe is equal to six mcf of natural gas or one bo of oil or NGLs based on a rough energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(3) Standardized measure is calculated in accordance with Accounting Standards Codification ("ASC"), Topic 932, Extractive Activities Oil and Gas. For further information regarding the calculation of the standardized measure, see "Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)" included in "Item 8. Financial Statements and Supplementary Data."

The data in the table above represents estimates only. Oil, NGLs and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil, NGLs and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, NGLs and natural gas that are ultimately recovered. For a discussion of risks associated with reserve estimates, please read "Item 1A. Risk Factors Our estimated reserves and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves."

Future prices realized for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure amounts shown above should not be construed as the current market value of our estimated oil and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by Financial Accounting Standard Board ("FASB") pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Development of Proved Undeveloped Reserves

None of our proved undeveloped reserves ("PUD") at December 31, 2014 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. Historically, our drilling and development programs were substantially funded from capital contributions, cash flow from operations and the issuance of debt and equity securities. Based on our current expectations of our cash flows and drilling and development programs, which includes drilling of proved undeveloped locations, we believe that we can fund the drilling of our current inventory of proved undeveloped locations and our expansions and extensions in the next five years from our cash on hand combined with cash flow from operations and utilization of available borrowing capacity under our credit facility. For a more detailed discussion of our liquidity position, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources."

Table of Contents

As of December 31, 2014, we identified 321 gross (247 net) PUD drilling locations which we anticipate drilling within the next five years. The table below details the activity in our PUD locations from December 31, 2013 to December 31, 2014:

	Net Oil (mbbl)	Net Natural Gas Liquids (mbbl)	Net Natural Gas (mmcf)	Net Volume (mboe)
PUDs as of December 31, 2013	27,447	3,306	19,574	34,015
Revisions of previous estimates	(2,020)	229	(3,916)	(2,444)
Extensions and discoveries	12,604	4,187	24,182	20,821
Purchases	6,792	11,992	78,046	31,792
Conversion to proved developed reserves during the year	(7,749)	(2,984)	(18,776)	(13,862)
PUDs as of December 31, 2014	37,074	16,730	99,110	70,322

We note that our proved reserve volumes contained in our reserve report include PUD locations that have a negative present value when discounted at 10%. There are a total of 61 such locations representing total net volumes of 18.1 mboe in our reserve report as of December 31, 2014. Despite the negative present value associated with these locations, management considers these locations economical on an undiscounted basis, and as such, is committed to developing these locations within the next five years. Excluding acquisitions, we expect to make capital expenditures related to drilling and completion of wells of approximately $560 to $600 million during the year ending December 31, 2015. We plan to spend approximately 60% to 70% of these capital expenditures on development of PUDs in 2015.

For more information about our historical costs associated with the development of proved undeveloped reserves, please read "Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)" included in "Item 8. Financial Statements and Supplementary Data."

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable financial measure in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves.

Table of Contents

The following table provides a reconciliation of PV-10 to the Standardized Measure at December 31, 2014 for our proved reserves (in millions):

	Proved Reserves
PV-10	$ 1,923.3
Present value of future income taxes discounted at 10%	(142.8)
Standardized Measure(1)	$ 1,780.5

(1) Standardized measure is calculated in accordance with ASC Topic 932, Extractive Activities Oil and Gas. For further information regarding the calculation of the standardized measure, see "Supplementary Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)" included in "Item 8. Financial Statements and Supplementary Data."

Table of Contents

Production, Revenues and Price History

The following table sets forth information regarding combined net production of oil, NGLs, and natural gas and certain price and cost information attributable to our properties for each of the periods presented:

	Year Ended December 31,		
	2014	**2013**	**2012**
Production:			
Oil mbo			
Catarina	846.7		
Marquis	1,910.4	724.5	67.4
Cotulla	1,868.1	1,098.3	87.8
Palmetto	1,422.6	1,085.6	262.7
Other	31.8	0.2	
Total	6,079.6	2,908.6	417.9
Natural gas liquids mbbl			
Catarina	1,579.5		
Marquis	251.2	63.8	
Cotulla	485.7	204.5	0.1
Palmetto	273.7	186.7	0.6
Total	2,590.1	455.0	0.7
Natural gas mmcf			
Catarina	9,244.2		
Marquis	974.4	383.7	
Cotulla	3,066.6	1,402.1	
Palmetto	1,542.3	1,234.4	226.7
Other		28.3	74.5
Total	14,827.5	3,048.5	301.2
Net production volumes:			
Total oil equivalent (mboe)	11,141.0	3,871.6	468.8
Average daily production (boe/d)	30,523.2	10,607.1	1,280.8
Average Sales Price(1):			
Oil ($ per bo)	$ 88.64	$ 99.82	$ 101.40
Natural gas liquids ($ per bbl)	$ 25.86	$ 28.60	$ 23.26
Natural gas ($ per mcf)	$ 4.06	$ 3.64	$ 2.54
Oil equivalent ($ per boe)	$ 59.79	$ 81.21	$ 92.07
Average unit costs per boe:			
Oil and natural gas production expenses	$ 8.40	$ 9.21	$ 7.26
Production and ad valorem taxes	$ 3.39	$ 4.47	$ 4.53
General and administrative(2)(3)	$ 4.56	$ 7.80	$ 24.95
Depreciation, depletion, amortization and accretion	$ 30.35	$ 34.82	$ 33.96

Impairment of oil and natural gas properties	$	19.19	$		$	

(1) Excludes the impact of derivative instruments.

(2) For the years ended December 31, 2014, 2013 and 2012, general and administrative excludes non-cash stock-based compensation expense of approximately $12.8 million ($1.15 per boe), $17.8 million ($4.58 per boe) and $25.5 million ($54.49 per boe), respectively.

(3) For the years ended December 31, 2014, 2013 and 2012, general and administrative includes acquisition costs included in general and administrative expense of $1.8 million ($0.16 per boe), $4.1 million ($1.07 per boe) and $0, respectively.

Table of Contents

Drilling Activities

The following table sets forth information with respect to wells drilled and completed during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value. At December 31, 2014, 45 gross wells were in various stages of completion.

	Year Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	115.0	82.0	84.0	59.5	14.0	9.5
Dry						
Exploratory wells:						
Productive	6.0	5.5	4.0	3.1	6.0	5.5
Dry						
Total wells:						
Productive	121.0	87.5	88.0	62.6	20.0	15.0
Dry						

The following table sets forth information at December 31, 2014 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Operated by us	189.0	155.2	201.0	198.7
Non-operated	94.0	34.7	1.0	0.3
Total	283.0	189.9	202.0	199.0

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2014 relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2014, 39% of our acreage was held by production.

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Catarina	14,625	14,625	91,445	91,445
Marquis	3,960	3,960	68,434	68,434
Cotulla	5,160	4,405	40,435	34,520
Palmetto	2,480	1,187	16,034	7,674
Total Eagle Ford	26,225	24,177	216,348	202,073
TMS	500	319	107,404	68,441
Total	26,725	24,496	323,752	270,514

Table of Contents

As of December 31, 2014, we had leases representing 33,173 net acres (32,961 of which were in the Eagle Ford Shale) expiring in 2015, 16,594 net acres (11,222 of which were in the Eagle Ford Shale) expiring in 2016, and 54,469 net acres (13,342 of which were in the Eagle Ford Shale) expiring in 2017 and beyond. We anticipate that our current and future drilling plans along with selected lease extensions will address the majority of our leases expiring in the Eagle Ford Shale in 2015 and beyond. In addition to these lease expirations, we also have a continuous development obligation in our Catarina area that requires us to drill, but not complete, (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120 day period in order to maintain rights to any future undeveloped acreage.

Delivery Commitments

We have made commitments to certain purchasers to deliver a portion of our natural gas production from our Cotulla and Catarina areas. The total amount contracted to be delivered in our Cotulla area is approximately 24 bcf of natural gas through 2021. The price for these deliveries is set at the time of delivery of the product. We have more production capacity than the amounts committed and none of the commitments in any given year are material.

In our Catarina area we have contracts with three processing facilities to deliver a portion of our natural gas production. The total amount contracted to be delivered in our Catarina area is approximately 175 bcf of natural gas with contracts expiring in 2016, 2018 and 2021. During 2014, we recorded expenses related to deficiencies on delivery commitments. These amounts were recorded to oil and natural gas production expenses in our consolidated statement of operations and were not considered material to the financial statement line item or to the consolidated financial statements as a whole. We expect to have additional expenses in 2015 related to deficiencies on our delivery commitments.

Operations

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any well drilled on the lease premises. The lessor royalties and other leasehold burdens on our properties range from 15.5% to 28.0%, resulting in a net revenue interest to us ranging from 84.5% to 72.0%.

Marketing and Major Customers

For the year ended December 31, 2014, purchases by three of our customers accounted for 37%, 23% and 15%, respectively, of our total revenues. The three customers purchase the oil, NGLs and natural gas production from us pursuant to existing marketing agreements with terms that are currently on "evergreen" status and renew on a month-to-month basis until either party gives 30-day advance written notice of non-renewal.

Since the oil, NGLs and natural gas that we sell are commodities for which there are a large number of potential buyers and because of the adequacy of the infrastructure to transport oil, NGLs and natural gas in the areas in which we operate, if we were to lose one or more customers, we believe that we could readily procure substitute or additional customers such that our production volumes would not be materially affected for any significant period of time.

Hedging Activities

We enter into commodity derivative contracts with unaffiliated third parties to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and natural gas

Table of Contents

prices. For a more detailed discussion of our hedging activities, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Costs and Operating Expenses Commodity Derivative Transactions," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Derivative Instruments" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Competition

We operate in a highly competitive environment for leasing and acquiring properties and in securing trained personnel. Our competitors specifically include major and independent oil and natural gas companies that operate in our project areas. These competitors include, but are not limited to, Chesapeake Energy Corporation, Marathon Oil Corporation, EOG Resources, Inc., Halcon Resources Corporation, and Penn Virginia Corporation. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry.

We are also affected by the competition for and the availability of equipment, including drilling rigs and completion equipment. We are unable to predict when, or if, shortages of such equipment may occur or how they would affect our development and exploitation programs.

Title to Properties

Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on significant leases, and depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title examinations have been obtained on a significant portion of our properties. After an acquisition, we review the assignments from the seller for scrivener's and other errors and execute and record corrective assignments as necessary.

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the titles to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report on Form 10-K.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months, resulting in seasonal fluctuations in the price we receive for our natural gas production. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the Environmental Protection Agency (the "EPA"), issue regulations, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for failure to comply. These laws and regulations may, among other things (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling, production and transportation activities; (iii) govern the sourcing and disposal of water used in the drilling and completion process; (iv) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (v) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (vi) result in the suspension or revocation of necessary permits, licenses and authorizations; (vii) impose substantial liabilities for pollution resulting from drilling and production operations; and (viii) require that additional pollution controls be installed. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of corrective or remedial obligations, and the issuance of orders enjoining performance of some or all of our operations. Furthermore, the strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that this trend will continue in the future.

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

Hazardous Substances and Waste Handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, or CERCLA, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or legality of conduct, on classes of persons considered to be responsible for the release, deemed "responsible parties," of a "hazardous substance" into the environment. These persons include the current owner or operator of the site where the release occurred, past owners or operators at the time a hazardous substance was released at the site, 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 strict and 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. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances, and despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties.

The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and their implementing regulations, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil and criminal penalties for alleged non-compliance with RCRA and analogous state requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas, if properly handled, are exempt from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is possible, however, that certain oil and natural gas exploration, development and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future and therefore be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as "hazardous wastes." 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.

Table of Contents

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we are in substantial compliance with the requirements of CERCLA, RCRA, and related state and local laws and regulations, that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations and 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, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water and Other Water Discharges and Spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act, or the SDWA, the Oil Pollution Act of 1990, or the OPA, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil, produced waters and other hazardous substances, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Obtaining permits also has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

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. Spill prevention, control and countermeasure, or SPCC, plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The OPA amends the Clean Water Act and establishes strict liability and natural resource damages liability for unauthorized discharges of oil into waters of the United States. The OPA is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs, as well as prepare Facility Response Plans for responding to a worst case discharge of oil into waters of the United States. Under the OPA, strict or joint and several liability may be imposed on "responsible parties" for all containment and cleanup costs and certain other damages arising from a

Table of Contents

release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. These laws and any implementing regulations may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement SPCC plans, in connection with on-site storage of significant quantities of oil. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

It is customary to recover oil and natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate oil and natural gas production. The protection of groundwater quality is extremely important to us. We believe that we follow all state and federal regulations and apply industry standard practices for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators. Our policy and practice is to follow all applicable guidelines and regulations in the areas where we conduct hydraulic fracturing. A surface casing string is set deeper than the deepest usable quality fresh water zones and cemented back to the surface in accordance with the appropriate regulations, potential lease requirements and legal requirements to ensure protection of existing fresh water zones. This surface string of casing is then pressure tested to ensure mechanical integrity of the casing string prior to continuing drilling operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions. The EPA, however, has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control, or UIC, Program. On February 12, 2014, the EPA published a revised UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how regulations of Class II wells, which are those wells injecting fluids associated with oil and natural gas production activities, may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. Although the EPA is not the permitting authority for UIC Class II programs in Texas and Louisiana, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned draft guidance.

Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. In addition, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014.

At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by March 2015, and legislation has been proposed before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, which legislation could be reintroduced in the current session of Congress.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, Texas recently adopted rules and regulations requiring that hydraulic fracturing well operators disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act, as

Table of Contents

amended, or OSHA, to state regulators and the public. Additionally, on October 28, 2014, the Texas Railroad Commission ("Commission") adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments also clarify the Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The disposal well rule amendments became effective on November 17, 2014. Also, in May 2013, the Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. On May 16, 2013, the U.S. Department of Interior, or DOI, issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm their wells meet certain construction standards; and (iii) establish site plans to manage flowback water. The DOI announced its intent to finalize the rule in 2014; however, the final rule remains pending. In addition, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in early 2015.

These or any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to drill and produce from conventional and tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. If hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

Air Emissions

The federal Clean Air Act, as amended, or the CAA, and comparable state laws, regulate emissions of various air pollutants through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. The rule includes NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely responsive to some of these requests. On September 23, 2013, EPA finalized the portion of the rule addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On December 19, 2014, the EPA released

Table of Contents

final updates and clarifications to the NSPS Standards. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address the methane and smog-forming VOC emissions from the oil and gas industry. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development of oil and natural gas projects, and our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, we do not believe that such requirements will have a material adverse effect on our operations.

Climate Change

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the CAA. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (the "Tailoring Rule") in May 2010, and it also became effective January 2011. The Tailoring Rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the CAA. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memorandums providing initial guidance on GHG permitting requirements in response to the Court's decision in UARG v. EPA. In its preliminary guidance, the EPA indicates it will undertake a rulemaking action no later than December 31, 2015 to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In addition, the EPA has continued to adopt GHG regulations of other industries, such as a September 2013 proposed GHG rule that, if finalized, would set New Source Performance Standards for new coal-fired and natural gas-fired power plants.

Table of Contents

In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Furthermore, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

These EPA and state programs, and the adoption of any legislation or regulations that otherwise limit emissions of GHGs from our equipment and operations, could require us to incur increased operating costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby adversely affect demand for the oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

National Environmental Policy Act

Oil and natural gas exploration, development and production activities on federal lands are subject to the National Environmental Policy Act, as amended, or NEPA. NEPA requires federal agencies, including the DOI, 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 to evaluate 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. Currently, we have minimal exploration and production activities on federal lands. For those current activities, however, as well as for future or proposed exploration and development plans, on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act

Additionally, environmental laws such as the Endangered Species Act, as amended, or the ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the U.S., and prohibits taking of endangered species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to insure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities on federal lands may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. The U.S. Fish and Wildlife Service may identify, however, previously unidentified endangered or threatened species or may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species, which could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Table of Contents

Occupational Safety and Health Act

We are also subject to the requirements of OSHA and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Additionally, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the oil and natural gas industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress, and the development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, we do not believe that compliance with these laws will have a material adverse impact on us.

Drilling and Production

Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the disclosure of the chemicals used in the hydraulic fracturing process;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Table of Contents

Natural Gas Regulation

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

The FERC also possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. FERC possesses substantial enforcement authority for violations of the Natural Gas Act, or NGA, including the ability to assess civil penalties, order disgorgement of profits and recommend criminal penalties. The Energy Policy Act of 2005 amended the NGA to grant FERC new authority to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce, and to prohibit market manipulation. FERC's anti-manipulation regulations apply to FERC jurisdictional activities, which have been broadly construed by the FERC. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial civil and criminal penalties, including civil penalties of up to $1.0 million per day, per violation.

In 2008, FERC took additional steps to enhance its market oversight and monitoring of the natural gas industry. Order No. 704, as clarified in orders on rehearing, requires buyers and sellers of natural gas above a de minimis level, including entities not otherwise subject to FERC jurisdiction, to submit an annual report to FERC describing their wholesale physical natural gas transactions that use an index or that contribute to or may contribute to the formation of a gas index. The FERC is currently contemplating expanding the industry's reporting requirements. On November 15, 2012, the FERC issued a Notice of Inquiry seeking comments whether requiring quarterly reporting of every gas transaction within the FERC's jurisdiction that entails physical delivery for the next day or the next month would provide useful information for improving natural gas market transparency. Comments on the Notice of Inquiry were submitted in February 2013. Following consideration of the comments received, FERC sent out data requests to certain marketers to obtain information related to natural gas sales transactions in July 2013.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of our properties. Sales of condensate and NGLs are not currently regulated and are made at market prices.

State Regulation

The various states regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amount of natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

Table of Contents

The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

We currently do not have any employees. Pursuant to our Services Agreement with SOG (the "Services Agreement"), SOG performs services for us, including the operation of our properties. Please also read Note 9, "Related Party Transactions." As of December 31, 2014, SOG had approximately 205 employees, including 21 engineers, 10 geoscientists and 15 land professionals. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that SOG's relations with its employees are satisfactory.

We also contract for the services of independent consultants involved in land, engineering, regulatory, accounting, financial and other disciplines as needed.

Offices

For our principal offices, we currently share offices with other members of the Sanchez Group under leases entered into by the Company covering approximately 90,000 square feet of office space in Houston, Texas at 1000 Main Street, Suite 3000, Houston, Texas 77002, expiring in 2025. In addition, SOG maintains offices in Laredo and San Antonio, Texas.

Available Information

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

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

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

Item 1A. *Risk Factors*

Our business involves a high degree of risk. You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this Annual Report on Form 10-K, including the financial statements and the related notes appearing at the end of this Annual Report on Form 10-K. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, business prospects, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones facing our company. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. This Annual Report on Form 10-K also contains forward-looking statements, estimates and projections that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of specific factors, including the risks described below.

Table of Contents

Risks Related to Our Business

Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in estimated reserves, estimated drilling costs or underlying assumptions will materially affect our business.

Exploring for and developing oil and natural gas reserves involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Exploratory wells bear a much greater risk of loss than development wells. Moreover, the successful drilling of an oil or natural gas well does not ensure a profit on investment. A variety of factors, both geological and market-related, can cause a well to become uneconomic or only marginally economic. Our initial drilling locations, and any potential additional locations that may be developed, require significant additional exploration and development, regulatory approval and commitments of resources prior to commercial development. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

Our estimated reserves and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

Numerous uncertainties are inherent in estimating quantities of oil, natural gas and NGL reserves and future production. It is not possible to measure underground accumulations of oil, natural gas and NGLs in an exact way. Oil, natural gas and NGL reserve engineering is complex, requiring subjective estimates of underground accumulations of oil, natural gas and NGLs and assumptions concerning future oil, natural gas and NGL prices, future production levels and operating and development costs. In estimating our level of oil, natural gas and NGL reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- the level of oil, natural gas and NGL prices;
- future production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation;
- the accuracy and reliability of the underlying engineering and geologic data; and
- the availability of funds.

If these assumptions prove to be incorrect, our estimates of our reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our estimated reserves could change significantly. For example, with other factors held constant, if the commodity prices used in our reserve report as of December 31, 2014 had decreased by 10%, then the standardized measure of our estimated proved reserves as of that date would have decreased by approximately $423 million, from approximately $1,781 million to approximately $1,358 million.

Our standardized measure is calculated using unhedged oil, natural gas and NGL prices and is determined in accordance with the rules and regulations of the SEC. Over time, we may make material

29

changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates we make for wells or fields that do not have a lengthy production history are less reliable than estimates for wells or fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures.

Prospects that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities.

Our prospects are in various stages of evaluation. There is no way to predict with certainty in advance of drilling and testing whether any particular prospect will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies, and the study of producing fields in the same area, will not enable us to know conclusively before drilling whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in commercially viable quantities. Moreover, the analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects.

Our estimated oil, natural gas and NGL reserves will naturally decline over time, and we may be unable to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations.

Our future oil, natural gas and NGL reserves, production volumes, and cash flow depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. Our estimated oil, natural gas and NGL reserves will naturally decline over time as they are produced. Our success depends on our ability to economically develop, find or acquire additional reserves to replace our own current and future production. If we are unable to do so, or if expected development is delayed, reduced or cancelled, the average decline rates will likely increase.

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

The cost of developing, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce as much oil, natural gas and NGLs as we had estimated. In addition, our use of 2D and 3D seismic data and visualization techniques to identify subsurface structures and hydrocarbon indicators do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures and requires greater pre-drilling expenditures than traditional drilling strategies. Furthermore, our development and production operations may be curtailed, delayed or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of rigs, equipment, labor or other services;
- composition of sour gas, including sulfur and mercaptan content;
- unexpected operational events and conditions;
- reductions in oil, natural gas and NGL prices;
- increases in severance taxes;
- adverse weather conditions and natural disasters;

Table of Contents

facility or equipment malfunctions and equipment failures or accidents, including acceleration of deterioration of our facilities and equipment due to the highly corrosive nature of sour gas;

title problems;

pipe or cement failures, casing collapses or other downhole failures;

compliance with ever-changing environmental and other governmental requirements;

environmental hazards, such as natural gas leaks, oil, natural gas and NGL spills, salt water spills, pipeline ruptures, discharges of toxic gases or other releases of hazardous substances;

lost or damaged oilfield development and service tools;

unusual or unexpected geological formations and pressure or irregularities in formations;

loss of drilling fluid circulation;

fires, blowouts, surface craterings and explosions;

uncontrollable flows of oil, natural gas, NGL or well fluids;

loss of leases due to incorrect payment of royalties;

limited availability of financing at acceptable rates; and

other hazards, including those associated with sour gas such as an accidental discharge of hydrogen sulfide gas, that could also result in personal injury and loss of life, pollution and suspension of operations.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our business, financial condition and results of operations.

We routinely apply hydraulic fracturing techniques in many of our drilling and completion operations. Hydraulic fracturing has recently become subject to increased public scrutiny and recent changes in federal and state law, as well as proposed legislative changes, could significantly restrict the use of hydraulic fracturing. Such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, such laws could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. If hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays, financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, as well as potential increases in costs. Please read " Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays" and "Item 1. Business Environmental Matters and Regulation Water and Other Water Discharges and Spills."

Additionally, hydraulic fracturing, drilling, transportation and processing of hydrocarbons bear an inherent risk of loss of containment. Potential consequences include loss of reserves, loss of production, loss of economic value associated with the affected wellbore, contamination of soil, ground water, and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

Table of Contents

Our acquisition, development and production operations require us to make substantial capital expenditures. Although we expect to fund our capital expenditure budget for 2015 using cash flow from operations and cash on hand, if our cash flow from operations turns out to be less than we currently expect and we are required, but are unable, to fund our remaining capital budget from other sources, such as borrowings under our credit facility and/or the issuance of debt or equity securities, our failure to obtain the funds that we need could have a material adverse effect on our business, financial condition and results of operations.

The oil and natural gas industry in which we operate is capital intensive and we must make substantial capital expenditures in our business for the acquisition, development and production of oil, natural gas and NGL reserves. Our cash on hand, cash flows from operations, ability to borrow and access to capital markets are subject to a number of variables, many of which are beyond our control, including:

- our estimated proved oil, natural gas and NGL reserves;
- the amount of oil, natural gas and NGLs we produce;
- the prices at which we sell our production;
- the results of our hedging strategy;
- the costs of developing, producing, and transporting our oil, natural gas and NGL assets, including costs attributable to governmental regulation and taxation;
- our ability to acquire, locate and produce new reserves;
- fluctuations in our working capital needs;
- interest payments, debt service and dividend payment requirements;
- prevailing economic conditions;
- our financial condition; and
- the ability and willingness of banks and other lenders to lend to us.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower oil, NGL or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have a reduced ability to obtain the capital necessary to sustain our operations at current levels. In addition, we may be unable to access the capital markets for debt or equity financing. If we are unsuccessful in obtaining the funds we need to fund our capital budget, we will be forced to reduce our capital expenditures, which in turn could lead to a decline in our production, revenues and our reserves, and could adversely affect our business, financial condition and results of operations.

Market conditions for oil, natural gas and NGLs, and particularly the recent declines in prices for these commodities, could adversely affect our revenue, cash flows, profitability and growth.

Prices for oil, natural gas and NGLs fluctuate widely in response to a variety of factors that are beyond our control, such as:

domestic and foreign supply of and demand for oil, natural gas and NGLs;

weather conditions and the occurrence of natural disasters;

overall domestic and global economic conditions;

political and economic conditions in oil, natural gas and NGL producing countries globally, including terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war;

- actions of OPEC and other state-controlled oil companies relating to oil price and production controls;
- the effect of increasing liquefied natural gas and exports from the United States;
- the impact of the U.S. dollar exchange rates on oil, natural gas and NGL prices;
- technological advances affecting energy supply and energy consumption;
- domestic and foreign governmental regulations, including regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells, and taxation;
- the impact of energy conservation efforts;
- the proximity, capacity, cost and availability of oil, natural gas and NGL pipelines and other transportation facilities;
- the availability of refining capacity; and
- the price and availability of alternative fuels.

In the past, oil, natural gas and NGL prices have been extremely volatile, and we expect this volatility to continue. Recently, oil prices have declined precipitously. For the twelve months ended December 31, 2014, the West Texas Intermediate posted price used to calculate the full cost ceiling in accordance with SEC rules declined from a high of $105.34 per bo on July 1, 2014 to $69.00 per bo on December 1, 2014. Such volatility may affect the amount of our net estimated proved reserves and will affect the standardized measure of discounted future net cash flows of our net estimated proved reserves. We recorded a full cost ceiling test impairment before income taxes of $213.8 million for the year ended December 31, 2014. The combined impact of lower commodity prices adversely affecting proved reserve values and the historical costs to drill and complete wells carried as proved undeveloped, as compared to current drilling and completion costs primarily contributed to the ceiling impairment. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. Given the current trend in commodity prices, the Company expects a continued decline in 12-month average commodity prices and therefore, we expect additional impairments could be recorded during 2015.

In addition, our revenue, profitability and cash flow depend upon the prices of and demand for oil, natural gas and NGL reserves, and a sustained drop in prices can significantly affect our financial results and impede our growth. In particular, sustained declines in commodity prices will:

- limit our ability to enter into commodity derivative contracts at attractive prices;
- reduce the value and quantities of our reserves, because declines in oil, natural gas and NGL prices would reduce the amount of oil, natural gas and NGLs that we can economically produce;
- reduce the amount of cash flow available for capital expenditures;

- limit our ability to borrow money or raise additional capital; and

- make it uneconomical for our operating partners to commence or continue production levels of oil, natural gas and NGLs.

An increase in the differential between the NYMEX or other benchmark prices of oil, natural gas and NGLs and the wellhead price we receive for our production could adversely affect our business, financial condition and results of operations.

The prices that we receive for our oil, natural gas and NGL production sometimes reflect differences between the relevant benchmark prices, such as NYMEX, that are used for calculating

Table of Contents

hedge positions. The difference between the benchmark price and the price we receive is called a basis differential. Increases in the basis differential between the benchmark prices for oil, natural gas and NGLs and the wellhead price we receive could adversely affect our business, financial condition and results of operations. We do not have or currently plan to have any commodity derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials, which could adversely affect our business, financial condition and results of operations.

As of February 26, 2015, we have commodity derivative contracts in place covering approximately 60% of the mid-point of our estimated oil and natural gas production for 2015. The contracts consist of swaps, enhanced swaps, collars, put spreads, and three-way costless collars, covering crude oil and natural gas production. In the future, we expect to continue to enter into commodity derivative contracts for a portion of our estimated production, which could result in net gains or losses on commodity derivatives. Our hedging strategy and future hedging transactions will be determined by our management, which is not under any obligation to enter into commodity derivative contracts covering any specific portion of our production.

The prices at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil, natural gas and NGL prices at the time we enter into these transactions, which may be substantially higher or lower than past or current oil, natural gas and NGL prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil, natural gas and NGL prices realized for our future production. Conversely, our hedging strategy may limit our ability to realize incremental cash flows from commodity price increases. As such, our hedging strategy may not protect us from changes in oil, natural gas and NGL prices that could have a significant adverse effect on our liquidity, business, financial condition and results of operations.

Economic uncertainty could negatively impact the prices for oil, natural gas and NGLs, limit access to the credit and equity markets, increase the cost of capital, and may have other negative consequences that we cannot predict.

If our cash flow from operations is less than anticipated and our access to capital is restricted because of economic uncertainty, we may be required to reduce our operating and capital budget, which could have a material adverse effect on our results and future operations. Ongoing uncertainty may also reduce the values we are able to realize in asset sales or other transactions we may engage in to raise capital, thus making these transactions more difficult and less economic to consummate. Additionally, demand for oil, natural gas and NGLs may deteriorate and result in lower prices for oil, natural gas and NGLs, which could have a negative impact on our revenues. Lower prices could also adversely affect the collectability of our trade receivables and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations.

Lower oil, natural gas and NGL prices may cause us to record ceiling limitation impairments, which would reduce our earnings and stockholders' equity.

We use the full-cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil, natural gas and NGL properties, including unproved and unevaluated property costs. Under full cost accounting rules, the net capitalized cost of oil, natural gas and NGL properties may not exceed a "ceiling limit" that is based upon the present value of estimated future net revenues from net proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties and other adjustments as required by SEC rules. If net capitalized costs of oil, natural gas and NGL properties exceed the ceiling limit, we must charge the amount of the excess to earnings, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. This is called a "ceiling limitation impairment." The risk that we will experience a ceiling limitation impairment increases when oil,

Table of Contents

natural gas or NGL prices are depressed, if we have substantial downward revisions in estimated net proved reserves or if estimates of future development costs increase significantly. Based upon current price trends we could experience ceiling limitation impairments in future periods.

As of December 31, 2014, the net book value of our oil and natural gas properties exceeded our ceiling amount using the WTI unweighted 12-month average price of $94.99/bo for oil, the Mt. Belvieu unweighted 12-month average price of $44.84/bbl for NGLs and the Henry Hub unweighted 12-month average price of $4.35/mmbtu for natural gas adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price realized at the wellhead, resulting in a write-down of our oil and natural gas properties of $213.8 million before income taxes. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is difficult to predict the likelihood, timing and magnitude of any future impairments. However, given the current trend in commodity prices, the Company expects a continued decline in 12-month average commodity prices, and, therefore, we expect additional impairments could be recorded during 2015. A ceiling test write down would negatively affect our results of operations.

Costs associated with unevaluated properties are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to amortization and the ceiling test limitation.

Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Substantial and sustained decreases in oil and natural gas prices would render uneconomic a significant portion of our development and exploitation projects. This may result in our having to make downward adjustments to our estimated proved reserves. As a result, substantial and sustained declines in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

The Company's derivative risk management activities could result in financial losses.

To mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities, support the Company's annual capital budgeting and expenditure plans and reduce commodity price risk associated with certain capital projects, the Company's strategy is to enter into derivative arrangements covering a portion of its oil, NGL and natural gas production. These derivative arrangements are subject to mark-to-market accounting treatment, and the changes in fair market value of the contracts are reported in the Company's statements of operations each quarter, which may result in significant non-cash gains or losses. These derivative contracts may also expose the Company to risk of financial loss in certain circumstances, including when:

- production is less than the contracted derivative volumes, in which case we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity;

- the counterparty to the derivative contract defaults on its contractual obligations;

- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge instrument; or
- the derivative contracts limit the benefit the Company would otherwise receive from increases in commodity prices.

Such financial losses could materially impact our liquidity, business, financial condition and results of operations.

Our stock price has been volatile, and investors in our common stock could incur substantial losses.

Our stock price has been volatile. For example, for the year ended December 31, 2014, our stock price had a high closing price of $38.13 per share and a low closing price of $6.48 per share. As a result of this volatility, investors may not be able to sell their common stock at or above the price at which they purchased their shares. The market price for our common stock may be influenced by many factors, including, but not limited to:

- the price of oil and natural gas;
- the success of our exploration and development operations, and the marketing of any oil we produce;
- regulatory developments in the United States;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;
- analysts' reports or recommendations;
- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- our issuance of any additional securities;
- investor perception of our company and of the industry in which we compete; and
- general economic, political and market conditions.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are extended.

Certain of our undeveloped leasehold acreage is subject to leases that will expire unless production in paying quantities is established during their primary terms or we obtain extensions of the leases. Our drilling plans for our undeveloped leasehold acreage are subject to change based upon various factors, including factors that are beyond our control, such as drilling results, oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Because of these uncertainties, we do not know if our undeveloped leasehold acreage will ever be drilled or if we will be able to produce crude oil, natural gas or NGLs from these or any other potential drilling locations. If our leases expire, we will lose our right to develop the related properties on this acreage. As of December 31, 2014, we had leases representing 33,173 net acres (32,961 of which were in the Eagle Ford Shale) expiring in 2015, 16,594 net acres (11,222 of which were in the Eagle Ford Shale) expiring in 2016, and 54,469 net acres (13,342 of which were in the Eagle Ford Shale) expiring in 2017 and beyond. While we anticipate that our current and future drilling plans will address the majority of our leases expiring in the Eagle Ford Shale in 2015, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operation. See "Business and Properties Properties Developed and Undeveloped Acreage" for additional information.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil, NGL and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil, NGL or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate revenue.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and properties, marketing oil, NGLs and natural gas, and securing equipment and trained personnel. Many of our competitors are large independent oil and natural gas companies that possess and employ financial, technical and personnel resources substantially greater than those of the Sanchez Group. Those entities may be able to develop and acquire more properties than our financial or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil, NGL and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business, financial condition and results of operations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in our wells and other operating properties and facilities, such as leaks, explosions, mechanical problems and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses. The location of our wells and other operating properties and facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs or on commercially reasonable terms. Changes in the insurance markets due to weather, adverse economic conditions, and the aftermath of the Macondo well incident in the Gulf of Mexico have made it more difficult for us to obtain certain types of coverage. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and we cannot be sure the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition and results of operations.

Our lack of diversification increases the risk of an investment in us and we are vulnerable to risks associated with operating in one major contiguous area.

Our current business focus is on the oil and natural gas industry in a limited number of properties, in the Eagle Ford Shale in South Texas and, to a lesser extent, the TMS in Southwest Mississippi and Southeast Louisiana. Larger companies have the ability to manage their risk by diversification. However, we currently lack diversification, in terms of both the nature and geographic scope of our business. For example, our Catarina assets, comprised of approximately 106,000 contiguous net acres in Dimmit, LaSalle and Webb Counties, Texas under the Catarina Lease, represent approximately 52% of our proved reserves as of December 31, 2014, approximately 47% of our Eagle Ford acreage as of December 31, 2014 and, on a pro forma basis, approximately 53% of our total production volumes for the year ended December 31, 2014. As a result, we will likely be impacted more acutely by factors affecting our industry or the regions in which we operate than we would if our business were more diversified, increasing our risk profile. In particular, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in which we have an interest that are caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from wells in the Eagle Ford Shale. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate all of the properties in which we own an ownership interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these non-operated properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production, revenues and reserves. The success and

Table of Contents

timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

- the nature and timing of the operator's drilling and other activities;
- the timing and amount of required capital expenditures;
- the operator's geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

Our ability to produce oil and natural gas could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production 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 waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas. The Clean Water Act imposes restrictions and strict controls regarding the discharge of produced waters and other oil and natural gas waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The Clean Water Act and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations, and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into coastal waters. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Indeed, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in early 2015. 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.

We may lose our rights to the Sanchez Group's technological database, including its 3D and 2D seismic data, under certain circumstances.

Pursuant to the Services Agreement, we have access to the unrestricted, proprietary portions of the technological database owned and maintained by the Sanchez Group and related to our properties, and SOG is otherwise required to interpret and use the database, to the extent relating to our properties, for our benefit under the Services Agreement. For a description of the Services Agreement see Note 9, "Related Party Transactions" in the notes to the consolidated financial statements in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K. This database includes the 2D and 3D seismic data used for our exploration and development projects as well as the well logs, LAS files, scanned well documents and other well documents and software that are necessary for our daily operations. This information is critical for the operation and expansion of our business. Under certain circumstances, including if SOG provides at least 180 days' advance written notice of its desire to terminate the Services Agreement, the license agreement will terminate and we will lose our rights to this technological database unless members of the Sanchez Group permit us to retain some or all of these rights, which they may decline to do in their sole discretion. In such event, we are unlikely to be able to obtain rights to similar information under substantially similar commercial terms or to continue our business operations as proposed and our liquidity, business, financial condition and results of operations will be materially and adversely affected and it could delay or prevent an acquisition of us.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology with respect to certain of our projects. The implementation and practical use of 3D seismic technology is relatively new, unproven and unconventional, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 3D seismic data over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 3D data without having an opportunity to attempt to benefit from those expenditures.

If we do not purchase additional acreage or make acquisitions on economically acceptable terms, our future growth will be limited.

Our ability to grow depends in part on our ability to make acquisitions on economically acceptable terms. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with their owners;
- unable to obtain financing for such acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to acquire properties containing estimated proved reserves, our total level of estimated proved reserves will decline as a result of our production.

Any acquisitions we complete or geographic expansions we undertake will be subject to substantial risks that could have a negative impact on our business, financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about estimated proved reserves, future production, revenues, capital expenditures, operating expenses and costs, including synergies, timing of expected development and the potential for expiration of underlying leaseholds;
- an inability to successfully integrate the assets or businesses we acquire;

- a decrease in our liquidity by using a significant portion of our cash and cash equivalents to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- the diversion of management's attention from other business concerns;
- mistaken assumptions about the overall cost of equity or debt;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- facts and circumstances that could give rise to significant cash and certain non-cash charges; and
- customer or key employee losses at the acquired businesses.

Further, we may in the future expand our operations into new geographic areas with operating conditions and a regulatory environment that may not be as familiar to us as our existing project areas. As a result, we may encounter obstacles that may cause us not to achieve the expected results of any such acquisitions, and any adverse conditions, regulations or developments related to any assets acquired in new geographic areas may have a negative impact on our business, financial condition and results of operations.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data and other information, the results of which are often inconclusive and subject to various interpretations. Our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition, given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Our completed acquisitions involve risks associated with acquisitions and integrating acquired assets, including the potential exposure to significant liabilities, and the intended benefits of these acquisitions may not be realized.

We have grown our business and our reserves through multiple significant acquisitions. Each of these acquisitions involves certain risks. The risks that we face associated with our acquisitions and integrating the assets acquired from these acquisitions into existing operations include:

- our senior management's attention being diverted from the management of daily operations to the integration of the acquired assets;
- our incurring significant unknown and contingent liabilities for which we have limited or no contractual remedies or insurance coverage;
- the acquired assets not performing as well as we anticipate; and

unexpected costs, delays and challenges that arise in integrating such assets into our existing operations.

Table of Contents

Even if we successfully integrate the assets acquired in our acquisitions into our operations, it may not be possible to realize the full benefits that we anticipate and/or we may not realize these benefits within the expected timeframe. If we fail to realize the benefits that we anticipate from our acquisitions, our business, results of operations and financial condition may be adversely affected.

Under the terms of the lease with respect to the Catarina assets, we are subject to annual drilling and development requirements and failure to comply with these requirements may result in loss of our interests in the Catarina area that are not held by production.

In order to protect our exploration and development rights in the Catarina area, we are required to meet certain drilling and other requirements under the lease with respect to this area (the "Catarina Lease"). For example, the Catarina Lease currently requires us to drill 50 wells per year (measured from July to July). If we fail to meet the minimum drilling commitment under the terms of the Catarina Lease, we would forfeit our acreage under the Catarina Lease and rights to develop land not held by production (excluding, in certain instances, associated rights such as midstream assets). In addition, the Catarina Lease requires us to go no longer than 120 days without spudding a well, and, under the terms of the Catarina Lease, failure to do so would result in the forfeiture of our acreage under the Catarina Lease and rights to develop land not held by production (excluding, in certain instances, acreage upon which associated midstream assets are located). Our drilling plans for our undeveloped leasehold acreage are subject to change based upon various factors, including factors that are beyond our control, such as drilling results, oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Because of these uncertainties, we cannot assure you that we will be able meet our obligations under the Catarina Lease. If the Catarina Lease expires, we will lose our right to develop the related properties on this acreage, which could adversely affect our business, financial condition and results of operations.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income.

As of December 31, 2014, we had net operating losses ("NOLs") carryforwards of $645.1 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code, our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Internal Revenue Code) at any time during a rolling three-year period.

We may not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions in order to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on, or to refinance, our debt obligations will depend on our financial and operating performance, which is subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We cannot assure you that our business will generate sufficient cash flows from operating activities or that future sources of capital will be available to us in an amount sufficient to permit us to service our indebtedness or to fund our other liquidity needs. If we are unable to generate sufficient cash flows to satisfy our debt obligations, we may have to undertake alternative financing plans, such as refinancing or restructuring our debt, selling assets, reducing or delaying capital investments or seeking to raise additional capital.

Table of Contents

We cannot assure you that any refinancing would be possible, that any assets could be sold or, if sold, of the timing of the sales and the amount of proceeds that may be realized from those sales, or that additional financing could be obtained on acceptable terms, if at all. Our credit facility and the indenture governing the Senior Notes (as defined in Note 5, "Long-Term Debt") contain restrictions on our ability to dispose of assets and our use of any of the proceeds. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations.

In addition, if we cannot make scheduled payments on our debt, we will be in default and, as a result:

- our debt holders could declare all outstanding principal and interest to be due and payable;
- the lenders under our revolving credit facility could terminate their commitments to lend us money and foreclose against the assets securing their borrowings; and
- we could be forced into bankruptcy or liquidation.

We may be able to incur substantially more debt. This could exacerbate the risks associated with our indebtedness.

Despite our current level of indebtedness, we and our subsidiaries may be able to incur substantial additional indebtedness in the future, including under our credit facility. As of December 31, 2014, we had $1.75 billion of debt outstanding, all of which was attributable to our Senior Notes, and a borrowing base of $650 million (with an elected commitment amount of $300 million) under our credit facility for secured revolver borrowings. Our increased indebtedness could adversely affect our business. In particular, it could increase our vulnerability to sustained, adverse macroeconomic weakness, limit our ability to obtain further financing and limit our ability to pursue certain operational and strategic opportunities. If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

We will be subject to interest rate risk in connection with borrowings under our credit facility, which bears interest at variable rates. Interest rate changes will not affect the market value of any debt incurred under such facility, but could affect the amount of our interest payments, and accordingly, our future earnings and cash flows, assuming other factors are held constant. We currently do not have any interest rate hedging arrangements with respect to our credit facilities, nor are any contemplated in the future. A significant increase in prevailing interest rates that results in a substantial increase in the interest rates applicable to our indebtedness could substantially increase our interest expense and have a material adverse effect on our financial condition and results of operations.

Restrictive covenants may adversely affect our operations.

Our credit facility and the indenture governing the Senior Notes contain a number of restrictive covenants that impose significant operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long-term best interest, including our ability, among other things, to:

- incur or assume additional debt or provide guarantees in respect of obligations of other persons;
- issue redeemable stock and preferred stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase certain debt;

Table of Contents

- make loans and investments;
- create or incur liens;
- restrict distributions from our subsidiaries;
- sell assets and capital stock of our subsidiaries;
- consolidate or merge with or into another entity, or sell all or substantially all of our assets; and
- enter into new lines of business.

A breach of the covenants under the indenture governing the Senior Notes or under our credit facility could result in an event of default under the applicable indebtedness. An event of default may allow the creditors to accelerate the related debt and may result in an acceleration of any other debt to which a cross-acceleration or cross-default provision applies. In addition, an event of default under our credit facility would permit the lenders under the facility to terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders under our credit facility could proceed against the collateral granted to them to secure that debt.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

The aggregate amount of our outstanding indebtedness could have important consequences for us, including the following:

- any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing such indebtedness;
- the covenants contained in our debt agreements limit our ability to borrow money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations and may limit our flexibility in operating our business;
- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;
- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially extended or further declines in oil and natural gas prices; and
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow from operations will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough cash to service our debt, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all.

The present value of future net revenues from our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil, natural gas and NGL reserves.

The present value of future net revenues from our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil, natural gas and NGL reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on the unweighted

Table of Contents

arithmetic average of the first-day-of-the-month prices for each month within the 12-month period prior to the end of the reporting period and costs in effect as of the date of the estimate. However, actual future net cash flows from our oil, natural gas and NGL properties also will be affected by factors such as:

- the actual prices we receive for oil, natural gas and NGLs;
- our actual operating costs in producing oil, natural gas and NGLs;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- the supply of and demand for oil, natural gas and NGLs; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from our estimated reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with ASC Topic 932, Extractive Activities Oil and Natural Gas, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

We have limited experience drilling wells on our TMS acreage, which has a short operational history and is subject to more uncertainties than our drilling program in more established formations.

We and other operators have begun drilling wells in the TMS only recently. Accordingly, there is limited information on which we can determine optimum drilling and completion strategies and drilling costs (which may be higher than other trends in which we operate), or estimate production decline rates or recoverable reserves from drilling on our acreage in this trend. Our drilling plans with respect to the TMS are flexible and depend on a number of factors, including the extent to which our initial wells in the trend are commercially successful.

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 a process used by oil and natural gas exploration and production operators in the completion of certain oil and natural gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate natural gas and, to a lesser extent, oil production. This process is typically regulated by state agencies. The EPA, however, has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal SDWA UIC Program. On February 12, 2014, the EPA published revised UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how regulations of Class II wells, which are those wells injecting fluids associated with oil and natural gas production activities, may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. Although the EPA is not the permitting authority for UIC Class II programs in Texas and Louisiana, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned draft guidance. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. In addition, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic

Table of Contents

Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014.

At the same time, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, with a draft of the study anticipated to be available by March 2015, and legislation has been proposed before Congress to provide for federal regulation of hydraulic fracturing and to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process, which legislation could be reintroduced in the current session of Congress. Further, certain members of the Congress have called upon the U.S. 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 U.S. 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.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, Texas recently adopted rules and regulations requiring that hydraulic fracturing well operators disclose the list of chemical ingredients subject to the requirements of OSHA to state regulators and the public. Additionally, on October 28, 2014, the Texas Railroad Commission, or the Commission, adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments also clarify the Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The disposal well rule amendments became effective on November 17, 2014. Also, in May 2013, the Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. On May 16, 2013, the DOI issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm their wells meet certain construction standards; and (iii) establish site plans to manage flowback water. The DOI announced its intent to finalize the rule in 2014, however, the final rule remains pending. These or any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to drill and produce from conventional or tight formations, increase our costs of compliance and doing business and make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings.

In addition, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in early 2015. We cannot predict the impact that these standards may have on our business at this time, but these standards could have a material impact on our business, financial condition and results of operation.

Table of Contents

In addition, in August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. The rule includes NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rule addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On December 19, 2014, the EPA released final updates and clarifications to the NSPS standards.

If hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our business, financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations. In addition, the third parties on whom we rely on for gathering and transportation services are also subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

Our oil and natural gas development and production operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. Please read "Item 1. Business Environmental Matters and Regulation" for a description of the laws and regulations that affect us.

In addition, the operations of the third parties on whom we rely for gathering and transportation services are also 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. Please read "Item 1. Business Environmental Matters

Table of Contents

and Regulation" for a description of the laws and regulations that affect the third parties on whom we rely.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

On April 2, 2007, the U.S. Supreme Court ruled, in Massachusetts, et al. v. EPA, that the CAA definition of "pollutant" includes carbon dioxide and other GHGs and, therefore, the EPA has the authority to regulate carbon dioxide emissions from automobiles. Thereafter, on December 15, 2009, the EPA published its findings that GHG emissions present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the CAA. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the Tailoring Rule in May 2010, and it also became effective January 2011. The Tailoring Rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the CAA. On June 23, 2014, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memorandums providing initial guidance on GHG permitting requirements in response to the Court's decision in Utility Air Regulatory Group v. EPA. In its preliminary guidance, the EPA indicates it will undertake a rulemaking action no later than December 31, 2015 to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In addition, the EPA has continued to adopt GHG regulations of other industries, such as a September 2013 proposed GHG rule that, if finalized, would set New Source Performance Standards for new coal-fired and natural gas-fired power plants.

In addition, Congress has from time to time considered legislation to reduce the emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Furthermore, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

Table of Contents

The EPA reporting rule and the adoption of any legislation or regulations that otherwise limit emissions of GHGs from our equipment and operations could require us to incur increased operating costs, such as costs to monitor and report GHG emissions, purchase and operate emissions control systems to reduce emissions of GHGs associated with our operations, acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thus could adversely affect demand for the oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. Please read "Item 1. Business Environmental Matters and Regulation."

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

We may incur significant delays, costs and liabilities as a result of stringent and complex environmental, health and safety requirements applicable to our oil and natural gas development and production operations. These laws and regulations may impose numerous obligations applicable to our operations, including that they may (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling, production and transportation activities; (iii) govern the sourcing and disposal of water used in the drilling and completion process; (iv) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (v) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (vi) result in the suspension or revocation of necessary permits, licenses and authorizations; (vii) impose substantial liabilities for pollution resulting from drilling and production operations; and (viii) require that additional pollution controls be installed. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict and joint and several liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our business, financial condition and results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or

Table of Contents

costly waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our competitive position, business, financial condition and results of operations. We may not be able to recover some or any of these costs from insurance. Please read "Item 1. Business Environmental Matters and Regulation" for more information.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, or CFTC, adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities.

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC has issued many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the "Mandatory Clearing Rule," requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), establishing an "end-user" exception to the Mandatory Clearing Rule, which we refer to as the "End-User Exception," and a rule, subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits. The CFTC proposed a new version of this rule, which we refer to as the "Re-Proposed Position Limit Rule," with respect to which the comment period has closed but a final rule has not been issued. In addition, the CFTC and bank regulators re-proposed rules, which we refer to as the "Re-Proposed SD/MSP Margin Rules," which, if adopted, would require that swap dealers and major swap participants receive initial and variation margin on uncleared swaps with financial end-users with material swaps exposures, swap dealers and major swap participants.

We qualify for and will utilize the End-User Exception to the Mandatory Clearing Rule if it is expanded to cover swaps in which we participate, our hedging and other activities are such that we will not be required to post margin under the Re-Proposed SD/MSP Margin Rules, if adopted, and the quantities under the swaps in which we participate are well within applicable limits under the Re-Proposed Position Limit Rule, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End-User Exception and, if the Re-Proposed SD/MSP Margin Rules are adopted, will be subject to such rule and required to post margin in accordance with such rule in connection with their swaps with other swap dealers and major swap participants. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule and the Re-Proposed SD/MSP Margin Rules are ultimately effected, such proposed rules could significantly increase the cost of our derivative contracts (including through our being required to post collateral), materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and production are eliminated as a result of future legislation.

Legislation is proposed from time to time that contains proposals to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. These proposals include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any of the foregoing proposals will actually be enacted or how soon any such changes in law could become effective. The passage of any legislation as a result of these proposals or any other similar change in U.S. federal income tax law could eliminate and/or defer certain tax deductions that are currently available with respect to oil and natural gas exploration and production. Any such change could materially adversely affect our business, financial condition and results of operations by increasing the after-tax costs we incur which would in turn make it uneconomic to drill some locations if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

We are subject to anti-takeover provisions in our restated certificate of incorporation and amended and restated bylaws and under Delaware law that could delay or prevent an acquisition of our company, even if the acquisition would be beneficial to our stockholders.

Provisions in our restated certificate of incorporation and amended and restated bylaws may delay or prevent an acquisition of us. These provisions may also frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our board of directors, who are responsible for appointing the members of our management team. Furthermore, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the Delaware General Corporation Law, which prohibits, with some exceptions, stockholders owning in excess of 15% of our outstanding voting stock from merging or combining with us. Finally, our amended and restated bylaws establish advance notice requirements for nominations for election to our board of directors and for proposing matters that can be acted upon at stockholder meetings. Although we believe these provisions together provide an opportunity to receive higher bids by requiring potential acquirers to negotiate with our board of directors, they would apply even if an offer to acquire us may be considered beneficial by some stockholders.

We are subject to legal proceedings and legal compliance risks.

We, including our officers and directors, are involved in various legal proceedings from time to time. Certain of these legal proceedings may be a significant distraction to management and could expose our Company to significant liability, including damages, fines, penalties and attorneys' fees and costs, any of which could have a material adverse effect on our business and results of operations.

We discuss the risks and uncertainties related to our litigation in more detail below in "Item 3. Legal Proceedings" and in Note 14, "Commitments and Contingencies."

Table of Contents

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended, and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

We are required to comply with laws, regulations and requirements, including the reporting obligations of the Exchange Act, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"), related regulations of the SEC and the requirements of the NYSE with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements requires a significant amount of time from our board of directors and management and has significantly increased our legal and financial compliance costs and made such compliance more time-consuming and costly. As compared to a private company, among other things, we are required to:

- maintain a more comprehensive compliance function;
- design, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- maintain internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities; and
- maintain an investor relations function.

In addition, as a public company subject to these rules and regulations, it may become more difficult and expensive for us to obtain director and officer liability insurance, and we may be required to accept greater coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified executive officers and qualified members to serve on our board of directors, particularly the audit committee of the board of directors (the "Audit Committee").

Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes-Oxley Act. Further, our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future. Any failure to remediate material weaknesses or significant deficiencies and to develop or maintain effective controls, or any difficulties encountered in our implementation or improvement of our internal controls over financial reporting could result in material misstatements that are not prevented or detected on a timely basis, which could potentially subject us to sanctions or investigations by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

Table of Contents

We have concluded that our internal control over financial reporting was not effective as of December 31, 2014 as a result of our identification of one material weakness related to an over-estimation of future development costs in the year-end reserve report. A material weakness in our internal controls could have a material adverse effect on us.

Controls over the estimation and review of our future development costs were not designed appropriately resulting in the estimates of future development costs in the reserve report not being adequately reduced for incurred and accrued current period drilling costs, and future development costs being over-estimated by approximately $85 million. This resulted in a control deficiency related to the estimation of future development costs included in the reserve report as of December 31, 2014.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis. In connection with our assessment of internal control over financial reporting under Section 404 of the Sarbanes-Oxley Act as of December 31, 2014, we identified a material weakness related to our future development cost estimates on the year-end reserve report. For a discussion of our internal control over financial reporting and a description of the identified material weakness, see "Management's Report on Internal Control Over Financial Reporting" included in Item 9A of this report.

Effective internal controls are necessary for us to provide reasonable assurance with respect to our financial reports and to effectively prevent fraud. If we cannot provide reasonable assurance with respect to our financial reports and effectively prevent fraud, our reputation and operating results could be harmed. Internal control over financial reporting may not prevent or detect misstatements because of its inherent limitations, including the possibility of human error, the circumvention or overriding of controls, or fraud. Further, the complexities of our quarter-end and year-end closing processes increase the risk that a weakness in internal controls over financial reporting may go undetected. Therefore, even effective internal controls can provide only reasonable assurance with respect to the preparation and fair presentation of financial statements. In addition, projections of any evaluation of effectiveness of internal control over financial reporting to future periods are subject to the risk that the control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness in our internal control over financial reporting could adversely impact our ability to provide timely and accurate financial information. We are working to remediate the material weakness discussed above and have begun taking steps and plan to take additional measures to remediate the underlying causes of the material weakness, primarily through the improvement of communication between accounting and engineering personnel and enhancing the review process over the inputs to the reserve report, which are further described in Item 9A of this report. We plan to complete this remediation process as quickly as possible. However, if our remedial measures are insufficient to address the material weakness or if additional material weaknesses or significant deficiencies in our internal control over financial reporting are discovered or occur in the future, we may not be able to timely or accurately report our financial condition, results of operations or cash flows or maintain effective disclosure controls and procedures. If we are unable to report financial information timely and accurately or to maintain effective disclosure controls and procedures, we could be subject to, among other things, regulatory or enforcement actions by the SEC and the NYSE, including a delisting from the NYSE, securities litigation, debt rating agency downgrades or rating withdrawals, any one of which could adversely affect the valuation of our common stock and could adversely affect our business prospects.

Table of Contents

We may have potential business conflicts of interest with members of the Sanchez Group regarding our past, ongoing and future relationships and the resolution of these conflicts may not be favorable to us.

Conflicts of interest may arise between members of the Sanchez Group and us in a number of areas relating to our past, ongoing and future relationships, including:

- labor, tax, employee benefit, indemnification and other matters arising under agreements with SOG;
- employee recruiting and retention;
- business opportunities that may be attractive to both members of the Sanchez Group and us; and
- business transactions that we enter into with members of the Sanchez Group.

We may not be able to resolve any potential conflicts, and, even if we do so, the resolution may be less favorable to us than if we were dealing with an unaffiliated party.

Finally, in connection with the IPO, we entered into several agreements with members of the Sanchez Group. These agreements were made in the context of a parent-subsidiary relationship. The terms of these agreements may be more or less favorable to us than if they had been negotiated with unaffiliated third parties.

Pursuant to the terms of our restated certificate of incorporation, members of the Sanchez Group are not required to offer corporate opportunities to us, and our directors and officers may be permitted to offer certain corporate opportunities to members of the Sanchez Group before us.

Our board of directors includes persons who are also directors and/or officers of members of the Sanchez Group. Our restated certificate of incorporation provides that:

- members of the Sanchez Group are free to compete with us in any activity or line of business;
- we do not have any interest or expectancy in any business opportunity, transaction, or other matter in which members of the Sanchez Group engage or seek to engage merely because we engage in the same or similar lines of business;
- to the fullest extent permitted by law, members of the Sanchez Group will have no duty to communicate their knowledge of, or offer, any potential business opportunity, transaction, or other matter to us, and members of the Sanchez Group are free to pursue or acquire such business opportunity, transaction, or other matter for themselves or direct the business opportunity, transaction, or other matter to its affiliates; and
- if any director or officer of any member of the Sanchez Group who is also one of our officers or directors becomes aware of a potential business opportunity, transaction, or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that business opportunity to us, and will be permitted to communicate or offer that business opportunity to such member of the Sanchez Group and that director or officer will not, to the fullest extent permitted by law, be deemed to have (1) breached or acted in a manner inconsistent with or opposed to his or her fiduciary or other duties to us regarding the business opportunity or (2) acted in bad faith or in a manner inconsistent with our best interests or those of our stockholders.

Table of Contents

We depend on SOG to provide us with certain services for our business. The services that SOG provides to us may not be sufficient to meet our needs, and we may have difficulty finding replacement services or be required to pay increased costs to replace these services after our agreements with SOG expire.

Certain services required by us for the operation of our business, including general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals, are provided by SOG pursuant to the Services Agreement. The services provided under the Services Agreement commenced on the date that the IPO closed and will terminate five years thereafter. The term automatically extends for additional 12-month periods and is terminable by either party at any time upon 180 days' written notice. See "Corporate Governance Compensation Committee" in the proxy statement for the 2015 annual meeting of stockholders, which is incorporated by reference to this report. While these services are being provided to us by SOG, our operational flexibility to modify or implement changes with respect to such services or the amounts we pay for them is limited. After the expiration or termination of this agreement, we may not be able to replace these services or enter into appropriate third-party agreements on terms and conditions, including cost, comparable to those that we will receive from SOG under our agreements with SOG.

In addition, SOG may outsource some or all of these services to third parties, and a failure of all or part of SOG's relationships with its outsourcing providers could lead to delays in or interruptions of these services. Our reliance on SOG and others as service providers and on SOG's outsourcing relationships, and our limited ability to control certain costs, could have a material adverse effect on our business, financial condition and results of operations.

A portion of our total outstanding shares is held by members of the Sanchez Group and may be sold into the market at any time. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

As of December 31, 2014, members of the Sanchez Group owned, in the aggregate, approximately 9% of our outstanding common stock. These shares are eligible for resale in the public markets, subject to the volume, manner of sale and other limitations under Rule 144 of the Securities Act. In addition, under certain circumstances, these persons have the right to require us to register the resale of their shares. Moreover, we have registered all of the shares of our common stock that we may issue under our employee benefit plans. These shares can be freely sold in the public market upon issuance unless, pursuant to their terms, these stock awards have transfer restrictions attached to them. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our common stock.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

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

Item 3. ***Legal Proceedings***

The information required by this Item is set forth in Note 14, "Commitments and Contingencies."

Item 4. ***Mine Safety Disclosures***

Not applicable.

Table of Contents

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Market for Registrant's Common Equity. Shares of our common stock are traded on the NYSE under the symbol "SN." The following table sets forth the reported high and low closing prices of our common stock for the periods indicated:

	Common Stock	
	High	Low
2014:		
First Quarter	$ 31.98	$ 23.85
Second Quarter	$ 38.13	$ 25.98
Third Quarter	$ 36.92	$ 26.26
Fourth Quarter	$ 25.20	$ 6.48

	Common Stock	
	High	Low
2013:		
First Quarter	$ 21.62	$ 17.10
Second Quarter	$ 23.43	$ 17.02
Third Quarter	$ 27.60	$ 20.40
Fourth Quarter	$ 30.92	$ 22.71

On February 26, 2015, the last sale price of our common stock, as reported on the NYSE, was $13.42 per share.

Holders. The number of shareholders of record of our common stock was approximately 38 on February 26, 2015, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or a bank.

Dividends. We pay dividends quarterly, in arrears, on each January 1, April 1, July 1 and October 1, when and if declared by the Company's board of directors on our Series A and Series B Convertible Perpetual Preferred Stock in the amounts of 4.875% and 6.50%, respectively. No dividends were accrued or accumulated prior to September 17, 2012. As of December 31, 2014, we have paid approximately $36.9 million in dividends to holders of our Series A and Series B Convertible Perpetual Preferred Stock since their respective issuances.

We have not paid any cash dividends on our common equity since our inception. Although our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities, we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings to finance the expansion of our business.

Securities Authorized for Issuance Under Equity Compensation Plans. The following table sets forth certain information as of December 31, 2014 regarding the Sanchez Energy Corporation Amended and

Table of Contents

Restated 2011 Long Term Incentive Plan (the "LTIP"). The LTIP was approved by our stockholders at our 2012 annual meeting of stockholders.

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 Stockholders		N/A	4,560,859(1)
Equity Compensation Plans Not Approved by Stockholders	N/A	N/A	N/A
Total			4,560,859

(1) The maximum number of shares that may be delivered pursuant to the LTIP is limited to 15% of our issued and outstanding shares of common stock. This maximum amount automatically increases to 15% of the issued and outstanding shares of common stock immediately after each issuance by us of our common stock, unless our board of directors determines to increase the maximum number of shares of common stock by a lesser amount.

Recent Sales of Unregistered Securities.

Period	Total Number of Shares Withheld(1)	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares That May Yet be Purchased Under the Plan
October 1, 2014 - October 31, 2014	1,279	$ 25.04		
November 1, 2014 - November 30, 2014		$		
December 1, 2014 - December 31, 2014		$		

(1) Represents shares that were withheld by us to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock.

Repurchases of Equity Securities. Neither we nor any "affiliated purchaser" repurchased any of our equity securities in the quarter ended December 31, 2014.

Comparative Stock Performance

The performance graph below compares the cumulative total stockholder return for our common stock to that of the Standard and Poor's, or S&P, 500 Index and the S&P 500 Oil & Gas Exploration and Production Index for the period indicated as prescribed by SEC rules. "Cumulative total return" means the change in share price during the measurement period divided by the share price at the beginning of the measurement period. The graph assumes $100 was invested on December 19, 2011 (the date on which our common stock began regular way trading on the NYSE) in each of our common stock, the S&P 500 Index and the S&P 500 Oil & Gas Exploration and Production Index.

**COMPARISON OF CUMULATIVE TOTAL RETURN
AMONG SANCHEZ ENERGY CORPORATION, THE S&P 500 INDEX,
AND THE S&P 500 OIL & GAS EXPLORATION AND PRODUCTION INDEX**

Note: The stock price performance of our common stock is not necessarily indicative of future performance.

The above information under the caption "Comparative Stock Performance" shall not be deemed to be "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

Item 6. *Selected Financial Data*

The selected financial data table below shows our historical consolidated financial data as of and for each of the five years in the period ended December 31, 2014. The selected financial data is derived from our audited historical financial statements.

Our historical financial statements prior to December 19, 2011 have been prepared on a carve-out basis from the accounts of SEP I. The carved-out financial information includes all assets, liabilities and results of operations of the unconventional oil and natural gas properties and related assets contributed to us by SEP I for the periods prior to December 19, 2011.

Our historical financial statements prior to December 19, 2011 included in this Annual Report on Form 10-K may not necessarily reflect our financial position, results of operations, and cash flows as if we had operated as a stand-alone public company during those periods. The historical financial data prior to December 19, 2011 reflect historical accounts attributable to the SEP I assets (the "SEP I Assets") on a "carve-out" basis, including allocated overhead from our predecessor in interest, for

Table of Contents

periods prior to our acquisition of the SEP I Assets on December 19, 2011 and do not reflect any estimate of additional overhead that we may incur as a separate company.

The selected financial data should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" included in this Annual Report on Form 10-K.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands, except per share amounts)				
REVENUES:					
Oil sales	$ 538,887	$ 290,322	$ 42,377	$ 13,905	$ 4,404
Natural gas liquids sales	66,989	13,013	15	22	
Natural gas sales	60,188	11,085	766	589	149
Total revenues	666,064	314,420	43,158	14,516	4,553
OPERATING COSTS AND EXPENSES:					
Oil and natural gas production expenses	93,581	35,669	3,401	1,628	391
Production and ad valorem taxes	37,787	17,334	2,124	830	214
Depreciation, depletion, amortization and accretion	338,097	134,845	15,922	4,252	1,430
Impairment of oil and natural gas properties	213,821				
General and administrative(1)	63,692	47,951	37,239	5,368	5,276
Total operating costs and expenses	746,978	235,799	58,686	12,078	7,311
Operating income (loss)	(80,914)	78,621	(15,528)	2,438	(2,758)
Other income (expense):					
Interest and other income	289	135	74	10	
Interest expense	(89,800)	(30,934)	(99)		
Net gains (losses) on commodity derivatives	137,205	(16,938)	(742)	(480)	
Total other income (expense)	47,694	(47,737)	(767)	(470)	
Income (loss) before income taxes	(33,220)	30,884	(16,295)	1,968	(2,758)
Income tax expense (benefit)	(11,429)	3,986			
Net income (loss)	(21,791)	26,898	(16,295)	1,968	(2,758)
Less:					
Preferred stock dividends	(33,590)	(18,525)	(2,112)		
Net income allocable to participating securities(2)(3)		(364)			
Net income (loss) attributable to common stockholders	$ (55,381)	$ 8,009	$ (18,407)	$ 1,968	$ (2,758)
Net income (loss) per common share basic and diluted	$ (1.06)	$ 0.22	$ (0.56)	$ 0.09	$ (0.12)
Weighted average number of shares used to calculate net income (loss) attributable to common stockholders basic and diluted(4)(5)	52,338	36,379	33,000	22,479	22,091

(1) Includes stock-based compensation expense of $12.8 million, $17.8 million and $25.5 million for the years ended December 31, 2014, 2013 and 2012, respectively.

(2) The Company's restricted shares of common stock are participating securities.

Table of Contents

(3)

For the years ended December 31, 2014 and 2012 no losses were allocated to participating restricted stock because such securities do not have a contractual obligation to share in the Company's losses. There were no outstanding shares of participating restricted stock for the years ended December 31, 2011 and 2010.

(4)

The year ended December 31, 2014 excludes 1,732,888 shares of weighted average restricted stock and 13,527,738 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive. The year ended December 31, 2013 excludes 757,963 shares of weighted average restricted stock and 14,979,225 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive. The year ended December 31, 2012 excludes 184,230 shares of weighted average restricted stock and 1,992,857 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive. The Company had no outstanding stock awards prior to its initial grants in January 2012.

(5)

Weighted average shares used to compute earnings (loss) per share for the year ended December 31, 2010 includes those shares issued to SEP I by the Company in connection with and as partial consideration for the acquisition of the SEP I Assets, which shares have been retroactively reflected as outstanding for all periods presented.

	As of December 31,				
	2014	2013	2012	2011	2010
	(in thousands)				
Balance Sheet Data:					
Working capital (deficit)	$ 379,556	$ 60,943	$ 15,671	$ 63,890	$ (1,818)
Total assets	$ 3,075,410	$ 1,629,153	$ 426,574	$ 217,356	$ 26,765
Long term debt, net of premium and discount	$ 1,746,263	$ 593,258	$	$	$
Total stockholders' equity / parent net investment	$ 999,587	$ 857,309	$ 366,743	$ 215,141	$ 22,162

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands)				
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ 415,335	$ 189,261	$ 29,072	$ 5,546	$ (3,777)
Net cash used in investing activities	$ (1,361,264)	$ (1,093,363)	$ (181,427)	$ (108,005)	$ (7,925)
Net cash provided by financing activities	$ 1,266,112	$ 1,007,286	$ 139,661	$ 165,500	$ 11,702

Non-GAAP Financial Measures

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss):

Plus:

Interest expense, including net losses (gains) on interest rate derivative contracts;

Table of Contents

Net losses (gains) on commodity derivative contracts;

Net settlements received (paid) on commodity derivative contracts;

Depreciation, depletion, and amortization and accretion;

Stock-based compensation expense;

Acquisition costs included in general and administrative;

Income tax expense (benefit);

Loss (gain) on sale of oil and natural gas properties;

Impairment of oil and natural gas properties; and

Other non-recurring items that we deem appropriate.

Less:

Premiums on commodity derivative contracts;

Interest income; and

Other non-recurring items that we deem appropriate.

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess:

our operating performance as compared to that of other companies and companies in our industry, without regard to financing methods, capital structure or historical cost basis; and

our ability to incur and service debt and fund capital expenditures.

Our Adjusted EBITDA should not be considered an alternative to net income (loss), operating income (loss), cash flows provided by (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

Table of Contents

The following table presents a reconciliation of our net income (loss) to Adjusted EBITDA (in thousands):

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Net income (loss)	$ (21,791)	$ 26,898	$ (16,295)	$ 1,968	$ (2,758)
Plus:					
Interest expense	89,800	30,934	99		
Net losses (gains) on commodity derivative contracts	(137,205)	16,938	742	480	
Net settlements received (paid) on commodity derivative contracts	5,600	(5,787)	2,749		
Depreciation, depletion, amortization and accretion	338,097	134,845	15,922	4,252	1,430
Impairment of oil and natural gas properties	213,821				
Stock-based compensation expense	12,843	17,751	25,542		
Acquisition costs included in general and administrative	1,808	4,129			
Income tax expense (benefit)	(11,429)	3,986			
Less:					
Premiums on commodity derivative contracts(1)	(718)	(2,838)	(3,059)		
Interest income	(193)	(190)	(74)	(1)	
Adjusted EBITDA	$ 490,633	$ 226,666	$ 25,626	$ 6,699	$ (1,328)

(1) This amount includes premiums accrued but not paid as of the end of the period.

The following table presents a reconciliation of net cash provided by (used in) operating activities to Adjusted EBITDA (in thousands):

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Net cash provided by (used in) operating activities	$ 415,335	$ 189,261	$ 29,072	$ 5,546	$ (3,777)
Net change in operating assets and liabilities	(6,238)	12,334	(3,806)	1,154	2,449
Interest expense, net(1)	79,850	23,584	(74)	(1)	
Accrued settlements on commodity derivative contracts(2)	(122)	(2,642)	434		
Acquisition costs included in general and administrative	1,808	4,129			
Adjusted EBITDA	$ 490,633	$ 226,666	$ 25,626	$ 6,699	$ (1,328)

(1) This amount includes cash interest expense on our Senior Notes and credit agreements, net of interest income.

(2) This amount includes premiums accrued but not paid as of the end of the period.

Adjusted Net Income (Loss)

We present adjusted net income (loss) attributable to common stockholders ("Adjusted Net Income (Loss)"), in addition to our reported net income (loss) in accordance with U.S. GAAP. This information is provided because management believes exclusion of the impact of the items included in our definition of Adjusted Net Income (Loss) below will help investors compare results between

62

Table of Contents

periods, identify operating trends that could otherwise be masked by these items and highlight the impact that commodity price volatility has on our results. We define Adjusted Net Income (Loss) as net income (loss):

Plus:

- Non-cash preferred stock dividends associated with conversion;
- Net losses (gains) on commodity derivative contracts;
- Net settlements received (paid) on commodity derivative contracts;
- Stock-based compensation expense;
- Acquisition costs included in general and administrative;
- Impairment of oil and natural gas properties;
- Other non-recurring items that we deem appropriate; and
- Tax impact of adjustments to net income (loss).

Less:

- Premiums on commodity derivative contracts;
- Preferred stock dividends; and
- Other non-recurring items that we deem appropriate.

Table of Contents

The following table presents a reconciliation of our net income (loss) to Adjusted Net Income (Loss) (in thousands, except per share data):

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Net income (loss)	$ (21,791)	$ 26,898	$ (16,295)	$ 1,968	$ (2,758)
Less: Preferred stock dividends	(33,590)	(18,525)	(2,112)		
Net income (loss) attributable to common shares and participating securities	(55,381)	8,373	(18,407)	1,968	(2,758)
Plus:					
Non-cash preferred stock dividends associated with conversion	17,297				
Net losses (gains) on commodity derivatives contracts	(137,205)	16,938	742	480	
Net settlements received (paid) on commodity derivative contracts	5,600	(5,787)	2,749		
Premiums on commodity derivative contracts(1)	(718)	(2,838)	(3,059)		
Impairment of oil and natural gas properties	213,821				
Stock-based compensation expense	12,843	17,751	25,542		
Acquisition costs included in general and administrative	1,808	4,129			
Tax impact of adjustments to net income (loss)(2)	(33,081)	(3,898)			
Adjusted net income (loss)	24,984	34,668	7,567	2,448	(2,758)
Adjusted net income allocable to participating securities(3)(4)	(1,157)	(1,513)	(221)		
Adjusted net income (loss) attributable to common stockholders	$ 23,827	$ 33,155	$ 7,346	$ 2,448	$ (2,758)
Adjusted net income (loss) per common share basic and diluted(5)(6)(7)	$ 0.46	$ 0.91	$ 0.22	$ 0.11	$ (0.12)
Weighted average number of unrestricted outstanding common shares to calculate adjusted net income (loss) per common share basic and diluted	52,338	36,379	33,000	22,479	22,091

(1) This amount includes premiums accrued but not paid as of the end of the period.

(2) The tax impact is computed by utilizing the Company's effective tax rate on the adjustments to reconcile net income (loss) to adjusted net income (loss).

(3) The Company's restricted shares of common stock are participating securities.

(4) There were no outstanding shares of participating restricted stock for the years ended December 31, 2011 and 2010.

(5)

The year ended December 31, 2014 excludes 1,732,888 shares of weighted average restricted stock and 13,527,738 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred

Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive.

(6) The year ended December 31, 2013 excludes 757,963 shares of weighted average restricted stock and 14,979,225 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive.

(7) The year ended December 31, 2012 excludes 184,230 shares of weighted average restricted stock and 1,992,857 shares of common stock resulting from an assumed conversion of the Company's Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive. The Company had no outstanding stock awards prior to its initial grants in January 2012.

Adjusted Net Income (Loss) is not intended to represent cash flows for the period, nor is it presented as a substitute for net income (loss), operating income (loss), cash flows provided by (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP.

Pro Forma net income (loss) and Pro forma Adjusted EBITDA

We present pro forma net income (loss) and pro forma adjusted EBITDA attributable to common stockholders ("pro forma Adjusted EBITDA") in addition to our reported net income (loss) in accordance with U.S. GAAP and historical Adjusted EBITDA. Pro forma net income and pro forma Adjusted EBITDA are non-GAAP financial measures that are used as supplemental financial measures by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess our operating performance after giving effect to our recent significant acquisitions as compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. They are also used to assess our ability to incur and service debt and fund capital expenditures. We define pro forma net income (loss) as net income (loss) plus adjustments to give effect to the acquisitions and related financing transactions identified in Note 3, "Acquisitions," which impacted the following accounts in our statement of operations:

- Total revenues (inclusive of oil sales, natural gas liquid sales and natural gas sales);
- Oil and natural gas production expenses;
- Production and ad valorem taxes;
- Depreciation, depletion, amortization and accretion;
- Impairment of oil and natural gas properties;
- Interest expense; and
- Income tax expense (benefit).

We define pro forma Adjusted EBITDA as pro forma net income (loss):

Plus:

- Pro forma interest expense, including net losses (gains) on interest rate derivative contracts;

Net losses (gains) on commodity derivative contracts;

Net settlements received (paid) on commodity derivative contracts;

Pro forma depreciation, depletion, amortization and accretion;

Table of Contents

Stock-based compensation expense;

Acquisition costs included in general and administrative;

Pro forma income tax expense (benefit);

Loss (gain) on sale of oil and natural gas properties;

Pro forma impairment of oil and natural gas properties; and

Other non-recurring items that we deem appropriate.

Less:

Premiums on commodity derivative contracts;

Interest income; and

Other non-recurring items that we deem appropriate.

Our pro forma net income (loss) and pro forma Adjusted EBITDA should not be considered as alternatives to net income (loss), operating income (loss), cash flows provided by (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP. Our pro forma net income (loss) and pro forma Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate pro forma net income (loss) and pro forma Adjusted EBITDA in the same manner.

The following unaudited pro forma combined results for each of the years in the five year period ended December 31, 2014 reflect the consolidated results of operations of the Company as if the Catarina acquisition and related financing had occurred on January 1, 2013 and the Wycross and Cotulla acquisitions and related financings had occurred on January 1, 2012. The following table presents a reconciliation of our net income to pro forma net income and pro forma Adjusted EBITDA (in thousands, except ratio data):

	Year Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Net income (loss)	$ (21,791)	$ 26,898	$ (16,295)	$ 1,968	$ (2,758)
Total revenues(a)	159,340	495,142	109,403		
Oil and natural gas production expenses(b)	(43,472)	(154,523)	(51,642)		
Production and ad valorem taxes(c)	(4,134)	(16,273)	(5,740)		
Depreciation, depletion, amortization and accretion(d)	(38,988)	(210,707)	(41,775)		
Impairment of oil and natural gas properties(e)	213,821				
Interest expense(f)(g)(h)	(16,735)	(49,826)	(29,338)		
Income tax benefit (expense)(i)	(92,839)	(21,956)			
Pro forma net income (loss)	155,202	68,755	(35,387)	1,968	(2,758)
Plus:					
Pro forma interest expense(j)	106,535	80,760	29,437		
Net losses (gains) on commodity derivative contracts(k)	(137,205)	16,938	742	480	
Net settlements received (paid) on commodity derivative contracts(k)	5,600	(5,787)	2,749		
Pro forma depreciation, depletion, amortization and accretion(l)	377,085	345,552	57,697	4,252	1,430
Stock-based compensation expense(k)	12,843	17,751	25,542		
Acquisition costs included in general and administrative(k)	1,808	4,129			
Pro forma income tax expense (benefit)(m)	81,410	25,942			
Less:					
Premiums on commodity derivative contracts(k)(p)	(718)	(2,838)	(3,059)		
Interest income(k)	(193)	(190)	(74)	(1)	
Pro forma Adjusted EBITDA	$ 602,367	$ 551,012	$ 77,647	$ 6,699	$ (1,328)

Total Debt(n)	1,750,000
Total Debt / Pro Forma LTM Adj. EBITDA	2.9
Net Debt(o)	1,276,286
Net Debt / Pro Forma LTM Adj. EBITDA	2.1

(a) Represents the increase in oil, natural gas liquids and natural gas sales resulting from the Catarina, Wycross and Cotulla acquisitions completed during 2013 and 2014.

(b) Represents the increase in oil and natural gas production expenses resulting from the Catarina, Wycross and Cotulla acquisitions completed during 2013 and 2014.

(c) Represents the increase in production and ad valorem taxes resulting from the Catarina, Wycross and Cotulla acquisitions completed during 2013 and 2014.

(d) Represents the increase in depreciation, depletion, amortization and accretion resulting from the Catarina, Wycross and Cotulla acquisitions completed during 2013 and 2014.

(e)
Represents the decrease in impairment of oil and natural gas properties resulting from the Catarina, Wycross and Cotulla acquisitions completed during 2013 and 2014.

(f)
Represents the pro forma interest expense and amortization of debt issuance costs related to borrowings under the Company's Amended and Restated Credit Agreement (as defined in Note 5, "Long-Term Debt") to fund a portion of the Cotulla acquisition completed during 2013, with interest expense calculated using an interest rate of 7.75% associated with the Original 7.75% Notes (as defined in Note 5, "Long-Term Debt") as the Original 7.75% Notes replaced the Amended and Restated Credit Agreement in financing a portion of the acquisition.

(g)
Represents the pro forma interest expense, amortization of debt issuance costs, and accretion of debt discount related to the issuance of the Additional 7.75% Notes (as defined in Note 5, "Long-Term Debt") to fund a portion of the Wycross acquisition completed during 2013.

(h)
Represents the pro forma interest expense and amortization of debt issuance costs related to the issuance of the Original 6.125% Notes (as defined in Note 5, "Long-Term Debt") to fund a portion of the Catarina acquisition completed in June 2014.

(i)
Represents the incremental income tax expense related to the pro forma effects of combining the Company's operations with the Catarina, Wycross and Cotulla assets' operations.

(j)
Represents historical interest expense of $89.8 million, $30.9 million, $0.1 million, $0 and $0 for the years ended December 31, 2014, 2013, 2012, 2011, and 2010, respectively, combined with pro forma adjustments to interest expense (as described in footnotes f, g, and h above) for each respective period.

(k)
Represents amounts as reported in the Company's historical statements of operations.

(l)
Represents historical depreciation, depletion, amortization and accretion of $338.1 million, $134.8 million, $15.9 million, $4.3 million and $1.4 million for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively, combined with pro forma adjustments to depreciation, depletion, amortization and accretion (as described in footnote d above) for each respective period.

(m)
Represents historical income tax expense (benefit) of ($11.4) million, $4.0 million, $0, $0 and $0 for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively, combined with pro forma adjustments to income tax expense (as described in footnote i above) for each respective period.

(n)
This amount does not include the debt discount of $7 million on the Additional 7.75% Notes and the debt premium of $2.3 million on the Additional 6.125% Notes (as defined in Note 5, "Long-Term Debt").

(o)
Net debt is calculated as the Company's total debt less its cash and cash equivalents from our consolidated balance sheet as of December 31, 2014.

(p)
This amount includes premiums accrued but not paid as of the end of the period.

Table of Contents

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K.

Business Overview

Sanchez Energy Corporation, a Delaware corporation formed in 2011, is an independent exploration and production company focused on the exploration, acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the Eagle Ford Shale in South Texas and, to a lesser extent, the TMS in Mississippi and Louisiana. We have accumulated approximately 226,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale and approximately 69,000 net leasehold acres in what we believe to be the core of the TMS. We are currently focused on the horizontal development of significant resource potential from the Eagle Ford Shale, with plans to invest approximately 93% of our 2015 drilling and completion capital budget in this area. We are continuously evaluating opportunities to grow both our acreage and our producing assets through acquisitions. Our successful acquisition of such assets will depend on both the opportunities and the financing alternatives available to us at the time we consider such opportunities. We have included definitions of some of the oil and natural gas terms used in this Annual Report on Form 10-K in the "Glossary of Selected Oil and Natural Gas Terms."

For further discussion of our business, including a description of various acquisitions completed during the periods presented in the consolidated financial statements, refer to "Item 1. Business Overview."

Basis of Presentation

The consolidated financial statements have been prepared in accordance with U.S. GAAP.

Our Properties

We and our predecessor entities have a long history in the Eagle Ford Shale, where we have assembled approximately 226,000 net leasehold acres with an average working interest of approximately 93%. Using approximately 40 acre well-spacing for our Cotulla and Palmetto areas, approximately 60 acre well-spacing for our Marquis area, and approximately 75 acre well-spacing for our Catarina area plus up to 650 additional upper Eagle Ford Catarina locations, and assuming 80% of the acreage is drillable for Cotulla, Marquis and Catarina, and 90% of the acreage is drillable for Palmetto, we believe that there could be over 3,500 gross (3,300 net) locations for potential future drilling. Consistent with other operators in this area, we perform multi-stage hydraulic fracturing up to 30 stages on each well depending upon the length of the lateral section. For the year 2015, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

Recent well results by other operators in the TMS area are encouraging with respect to both strong well performance and decreasing drilling and completion costs. We plan to allocate 6% of our total 2015 capital budgets to this area. The average remaining lease term on the acreage is over 3 years, giving us ample time to allow other industry participants to further de-risk the play.

For further discussion of our properties, including a description of recent well results in our core operating areas, refer to "Item 1. Business Core Properties."

Table of Contents

Recent Developments

During the fourth quarter of 2014 oil prices began a substantial and rapid decline which has continued into early 2015. In response to that decline, the Company initiated a series of financial and operational activities highlighted below. Our capital budget was substantially reduced, first in November 2014, and then again in January 2015, to the current planned amount of $600 to $650 million. In addition, we have taken steps which have already resulted in substantial cost reductions in the drilling and completion of wells and also have other cost reduction activities underway such that by the second half of 2015, we expect our annualized run rate of capital expenditures to decrease to a range of $400 to $450 million while still allowing us to grow our annual production.

Significant market and operational factors impacting our current results and future expectations include:

- The substantial and rapid decline in oil prices described above,

- The declining oil prices impact many of the metrics used to evaluate the Company, including revenue, Adjusted EBITDA, and operating cash flows. In the light of the current trend in market prices, historical figures may not be indicative of future expectations,

- The Company believes it can fully fund its capital spending plan for 2015 from cash on hand and internally generated cash flows, leaving the borrowing capacity under its Second Amended and Restated Credit Agreement unused while still being able to modestly increase production volumes year over year,

- The Company's borrowing base is scheduled to be re-determined in 2015. It is not expected that any potential future changes to our borrowing base would impact our elected commitment amount or our ability to fund our anticipated activity,

- Our 2015 capital budget has been substantially reduced to a current planned amount of $600 to $650 million, as compared to actual capital expenditures in 2014 (excluding acquisition activity) of approximately $800 million,

- The 2015 capital budget remains subject to further adjustments, depending on market conditions, and the Company maintains significant flexibility in our operations to be able to increase or decrease our capital budget quickly to react to changes in market conditions,

- Although always a focus of the Company, in the current environment, we have emphasized the strategy to enhance returns through operational and cost efficiencies throughout the Company,

- We still intend to evaluate and pursue strategic acquisitions that will benefit the Company through cost effective additions to Company's current and/or future operations and reserve base,

- Our Catarina acquisition in 2014 has had a positive impact on our reserves and financial position, and based on the significant potential for development of both upper and lower Eagle Ford zones in the area, we expect to see a continued increase in the upside of the acquisition in 2015 and beyond,

- In February 2015, the Company modified certain of its crude oil enhanced swap and three-way collar transactions to create crude oil swaps on a costless transactional basis. The modification to a fixed price eliminates downside risk, preserves value and provides the Company with greater certainty in crude oil pricing for the remainder of 2015, We have commodity derivative contracts in place covering approximately 60% of the mid-point of our estimated total production for 2015 and

Based on the expectation that the current decline in average prices will continue during 2015, the Company could incur additional non-cash impairments to our full cost pool in 2015.

Table of Contents

Outlook

Due to the uncertainty regarding future commodity prices, the Company plans to manage its operating activities and financial liquidity carefully. Based on current levels of commodity prices, we expect to be able to fund the current 2015 capital program with cash on hand and operating cash flow. We believe the results of that capital program will allow us to modestly grow our total production of hydrocarbons over the levels we reported for 2014. We plan to continuously evaluate our level of operating activity in light of both actual commodity prices and changes we are able to make to our costs of operations and make further adjustments to our capital spending program as appropriate. In addition, we expect to continue to regularly review acquisition opportunities from third parties or other members of the Sanchez Group.

The average oil price, WTI Cushing, used in the SEC pricing methodology for calculating the PV-10 and Standardized Measures and for performing impairment tests under the full cost method, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2014 was $94.99 per barrel and the average natural gas price, at Henry Hub, and calculated in the same manner, was $4.35 per mmbtu. As a result of less favorable commodity prices adversely affecting proved reserve values and the historical costs to drill and complete wells carried as proved undeveloped, as compared to current drilling and completion costs, we recorded a full cost ceiling test impairment before income taxes of $213.8 million for the year ended December 31, 2014. Based on the decline in average prices since December 31, 2014 and a current expectation that prices will continue to decline during 2015 based upon the current NYMEX forward prices, absent a material addition to proved reserves and/or a material reduction in future development costs, there is a reasonable likelihood that the Company would incur additional impairments to our full cost pool in 2015.

Table of Contents

Results of Operations

Revenue and Production

The following table summarizes production, average sales prices and operating revenue for our oil, NGLs and natural gas operations for the periods indicated (in thousands, except average sales price and percentages):

	Year Ended December 31,			Increase (Decrease) 2014 vs 2013		2013 vs 2012	
	2014	2013	2012	$	%	$	%
Net Production:							
Oil (mbo)	6,079.6	2,908.6	417.9	3,171.0	109%	2,490.7	*
Natural gas liquids (mbbl)	2,590.1	455.0	0.7	2,135.1	*	454.3	*
Natural gas (mmcf)	14,827.5	3,048.5	301.2	11,779.0	*	2,747.3	*
Total oil equivalent (mboe)	11,141.0	3,871.6	468.8	7,269.4	188%	3,402.8	*
Average Sales Price Excluding Derivatives(1):							
Oil ($ per bo)	$ 88.64	$ 99.82	$ 101.40	$ (11.18)	(11)%	$ (1.58)	(2)%
Natural gas liquids ($ per bbl)	$ 25.86	$ 28.60	$ 23.26	$ (2.74)	(10)%	$ 5.34	23%
Natural gas ($ per mcf)	$ 4.06	$ 3.64	$ 2.54	$ 0.42	12%	$ 1.10	43%
Oil equivalent ($ per boe)	$ 59.79	$ 81.21	$ 92.07	$ (21.43)	(26)%	$ (10.86)	(12)%
Average Sales Price Including Derivatives(2):							
Oil ($ per bo)	$ 89.26	$ 96.86	$ 100.66	$ (7.60)	(8)%	$ (3.80)	(4)%
Natural gas liquids ($ per bbl)	$ 25.86	$ 28.60	$ 23.26	$ (2.74)	(10)%	$ 5.34	23%
Natural gas ($ per mcf)	$ 4.13	$ 3.63	$ 2.54	$ 0.50	14%	$ 1.09	43%
Oil equivalent ($ per boe)	$ 60.22	$ 78.98	$ 91.40	$ (18.76)	(24)%	$ (12.42)	(14)%
REVENUES(1):							
Oil sales	$ 538,887	$ 290,322	$ 42,377	$ 248,565	86%	$ 247,945	*
Natural gas liquids sales	66,989	13,013	15	53,976	*	12,998	*
Natural gas sales	60,188	11,085	766	49,103	*	10,319	*
Total revenues	$ 666,064	$ 314,420	$ 43,158	$ 351,644	112%	$ 271,262	*

* Not meaningful.

(1) Excludes the realized impact of derivative instruments.

(2) Includes the realized impact of derivative instruments.

Net Production. Production increased from 468.8 mboe in 2012 to 11,141.0 mboe in 2014 due to our drilling program and acquisition activity. As detailed in the following table, the Catarina acquisition added 3,966.9 mboe of production during the final six months of 2014 after the closing date of June 30,

Table of Contents

2014. The number of gross wells producing at year end and the production for the periods were as follows:

	Year Ended December 31,					
	2014		2013		2012	
	# Wells	mboe	# Wells	mboe	# Wells	mboe
Catarina	193	3,966.9				
Marquis	90	2,324.0	34	852.2	3	67.4
Cotulla	129	3,047.6	100	1,536.4	10	87.9
Palmetto	64	1,770.7	53	1,478.1	18	301.1
Other	9	31.8	1	4.9	1	12.4
Total	485	11,141.0	188	3,871.6	32	468.8

In 2014, 55% of our production was oil, 23% was NGLs and 22% was natural gas compared to 2013 production that was 75% oil, 12% NGLs and 13% natural gas. In 2012, 89% of our production was oil, de minimis NGLs and 11% was natural gas. The change in production mix during the year ended December 31, 2014 was due to the Catarina acquisition and the higher proportion of NGL and natural gas production as compared to oil production from this area.

Revenues. Oil, NGL and natural gas sales revenues totaled approximately $666.1 million, $314.4 million and $43.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. Oil, NGL and natural gas sales revenue for the year ended December 31, 2014 increased $248.6 million, $54.0 million and $49.1 million as compared to the year ended December 31, 2013, respectively.

The following tables provide an analysis of the impacts of changes in average realized prices and production volumes between the periods on our revenues from the year ended December 31, 2013 to the year ended December 31, 2014 (in thousands, except average sales price):

	2014 Production Volume	2013 Production Volume	Production Volume Difference	2013 Average Sales Price	Revenue Increase/(Decrease) due to Production
Oil (mbo)	6,079.6	2,908.6	3,171.0	$ 99.82	$ 316,513
Natural gas liquids (mbbl)	2,590.1	455.0	2,135.1	$ 28.60	$ 61,064
Natural gas (mmcf)	14,827.5	3,048.5	11,779.0	$ 3.64	$ 42,831
Total oil equivalent (mboe)	11,141.0	3,871.6	7,269.4	$ 81.21	$ 590,362

	2014 Average Sales Price	2013 Average Sales Price	Average Sales Price Difference	2014 Volume	Revenue Increase/(Decrease) due to Price
Oil (mbo)	$ 88.64	$ 99.82	$ (11.18)	6,079.6	$ (67,948)
Natural gas liquids (mbbl)	$ 25.86	$ 28.60	$ (2.74)	2,590.1	$ (7,088)
Natural gas (mmcf)	$ 4.06	$ 3.64	$ 0.42	14,827.5	$ 6,272
Total oil equivalent (mboe)	$ 59.79	$ 81.21	$ (21.43)	11,141.0	$ (238,718)

Additionally, a 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the year ended December 31, 2014 by $66.6 million.

For the year ended December 31, 2013 compared to 2012, oil sales revenue increased $247.9 million with $252.5 million attributable to the increase in production partially offset by $4.6 million due to the lower average sales price. NGL sales revenue for the year ended December 31, 2013 increased $13.0 million as compared to 2012, with $10.6 million attributable to the increase in

Table of Contents

production and $2.4 million attributable to the higher average sales prices between the periods. Natural gas sales revenue for the year ended December 31, 2013 increased approximately $10.3 million with $7.0 million attributable to the increase in production and $3.3 million due to the higher average sales price compared to 2012.

Operating Costs and Expenses

The table below presents a detail of operating costs and expenses for the periods indicated (in thousands except percentages):

	Year Ended December 31,			Increase (Decrease)			
				2014 vs 2013		2013 vs 2012	
	2014	2013	2012	$	%	$	%
OPERATING COSTS AND EXPENSES:							
Oil and natural gas production expenses	$ 93,581	$ 35,669	$ 3,401	$ 57,912	162%	$ 32,268	*
Production and ad valorem taxes	37,787	17,334	2,124	20,453	118%	15,210	*
Depreciation, depletion, amortization and accretion	338,097	134,845	15,922	203,252	151%	118,923	*
Impairment of oil and natural gas properties	213,821			213,821	*		*
General and administrative (inclusive of stock-based compensation expense of $12,843, $17,751 and $25,542 for the years ended December 31, 2014, 2013 and 2012, respectively)	63,692	47,951	37,239	15,741	33%	10,712	29%
Total operating costs and expenses	746,978	235,799	58,686	511,179	217%	177,113	*
Interest and other income	289	135	74	154	114%	61	82%
Interest expense	(89,800)	(30,934)	(99)	58,866	*	30,835	*
Net gains (losses) on commodity derivatives	137,205	(16,938)	(742)	154,143	*	(16,196)	*
Income tax benefit (expense)	11,429	(3,986)		15,415	*	(3,986)	*

*

Not meaningful.

Oil and Natural Gas Production Expenses. Oil and natural gas production expenses are the costs incurred to produce our oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional well workover expenses related to our oil and natural gas properties. Our oil and natural gas production expenses increased 162% to $93.6 million for the year ended December 31, 2014, as compared to $35.7 million for the same period in 2013 and $3.4 million for the same period in 2012. The increase in oil and natural gas production expenses from 2012 to 2014 is directly attributable to our increased production activities and well count in the Eagle Ford Shale, as a result of the Catarina, Wycross and Cotulla acquisitions completed during 2014 and 2013, as well as drilling activities on our existing acreage. Our average production expenses decreased from $9.21 per boe during the year ended December 31, 2013 to $8.40 per boe for the year ended December 31, 2014. This decrease was due primarily to increased efficiency in our overall operations between the periods. While we expect our oil and natural gas production expenses to increase as we add producing wells, we expect to continue our efficient operation of our properties, and do not expect significant increases in our average production expenses per boe.

Production and Ad Valorem Taxes. Production and ad valorem taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. Our production and ad valorem taxes totaled $37.8 million, $17.3 million and $2.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. This tax increase was

Table of Contents

due to the significant increase in revenues of over 1,400% between these periods. Our average production and ad valorem taxes decreased from $4.47 per boe during the year ended December 31, 2013 to $3.39 per boe for the year ended December 31, 2014. This decrease in rate is directly attributable to the significantly lower applicable production tax rate in the Catarina area, which accounted for approximately 52% of our total production in the second half of 2014. This lower rate is the result of the characterization of the wells in the Catarina area as high cost gas wells. While this rate may vary depending on the actual capital costs incurred on a well by well basis, we expect the production tax rate to continue to be lower than the rates established in our other operating areas.

Depreciation, Depletion, Amortization, and Accretion. Depletion, depreciation, amortization, and accretion ("DD&A") reflects the systematic expensing of the capitalized costs incurred in the acquisition, exploration and development of oil and natural gas properties. We use the full-cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil and natural gas properties, including unproved and unevaluated property costs. Internal costs are capitalized only to the extent they are directly related to acquisition, exploration and development activities and do not include any costs related to production, selling or general corporate administrative activities. Capitalized costs of oil and natural gas properties are amortized using the units of production method based upon production and estimates of proved oil and natural gas reserve quantities. Unproved and unevaluated property costs are excluded from the amortizable base used to determine DD&A expense.

Our DD&A expense for the year ended December 31, 2014 increased $203.3 million to $338.1 million ($30.35 per boe) from $134.8 million ($34.82 per boe) in 2013 and $15.9 million in 2012 ($33.96 per boe). The majority of the increase in DD&A is related to an increase in depletion resulting primarily from a substantial increase in production between periods. This was offset by a decrease in the depletion rate, resulting from an increase in the estimated proved reserves during the period, largely as a result of the Catarina acquisition. Estimated proved reserves as of December 31, 2014 were 129% higher than estimated proved reserves as of December 31, 2013. Offsetting this was the increase in future development costs for our PUDs to $1,640.0 million, an increase of 82% over the December 31, 2013 estimate of $900.8 million. Higher production in 2014 as compared to 2013 resulted in a $252.4 million increase in depletion expense and the change in depletion rate resulted in a $51.1 million decrease in depletion expense. The remaining increases of $2.0 million and $2.4 million in DD&A as compared to the years ended December 31, 2013 and 2012, respectively, are related to increases in depreciation, amortization and accretion between the periods presented.

Impairment of Oil and Natural Gas Properties. We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling," based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. We recorded a full cost ceiling test impairment before income taxes of $213.8 million for the year ended December 31, 2014. The combined impact of less favorable commodity prices adversely affecting proved reserve values and the historical costs to drill and complete wells carried as proved undeveloped, as compared to current drilling and completion costs, contributed to the ceiling impairment. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. Given the current trend in commodity prices, the Company expects a continued decline in 12-month average commodity prices, and, therefore, we expect additional impairments could be recorded during 2015.

General and Administrative Expenses. Our general and administrative ("G&A") expenses, including stock-based compensation expense, totaled $63.7 million for the year ended December 31, 2014 compared to $48.0 million and $37.2 million for the same periods in 2013 and 2012, respectively. Excluding the stock-based compensation, G&A expenses totaled $50.8 million, $30.2 million and $11.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. This increase was due primarily to additional costs for added personnel at SOG performing services for the Company and for consulting services. Our G&A expenses, excluding stock-based compensation expense and acquisition costs included in G&A, decreased from $6.73 per boe for the year ended December 31, 2013 to $4.40 per boe for the year ended December 31, 2014. We also recorded costs associated with acquisitions during the years ended December 31, 2014 and 2013 of $1.8 million (in connection with the Catarina acquisition) and $4.1 million (in connection with the Wycross, Five Mile Creek and Cotulla acqusitions), respectively.

We recorded non-cash stock-based compensation expense of $12.8 million for the year ended December 31, 2014 as compared to expense of $17.8 million for the year ended December 31, 2013. The decrease was due primarily to the decrease in stock price offset by an increase in awards made during the year and the associated amortization recognized. The Company records stock-based compensation expense for awards granted to non-employees at fair value and the unvested awards are revalued each period, impacting the amortization over the remaining life of the awards. For the year ended December 31, 2012, we recorded a non-cash stock-based compensation expense of approximately $25.5 million primarily related to the rescission and cancellation of 1.1 million shares of restricted stock during the second quarter of 2012. The restricted stock awards were granted to non-employees such that upon rescission and cancellation, stock-based compensation expense was based on the fair value at the date of cancellation, and the associated unrecognized compensation expense was accelerated and recognized as stock-based compensation expense. At the date of cancellation, the fair value of the stock awards cancelled was approximately $22.3 million, or $20.28 per restricted share.

Interest Expense. For the year ended December 31, 2014, interest expense totaled $89.8 million and included $9.0 million in amortization of debt issuance costs and write-offs of previously incurred debt issuance costs in connection with the unused senior unsecured bridge facility obtained as part of the Catarina acquisition that expired. This is compared to the year ended December 31, 2013, for which interest expense totaled $30.9 million and included $6.9 million in amortization of debt issuance costs and write-offs of previously incurred debt issuance costs in connection with the termination of the Second Lien Term Credit Agreement (the "Second Lien Credit Agreement") and the commitment for the bridge loan credit facility, as well as in connection with the modification of the First Lien Credit Agreement (the "Original Credit Agreement") during the period. The interest expense incurred during the year ended December 31, 2014 is primarily related to the 7.75% Notes (as defined in Note 5, "Long-Term Debt") and 6.125% Notes (as defined in Note 5, "Long-Term Debt").

Commodity Derivative Transactions. We apply mark-to-market accounting to our derivative contracts; therefore the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in other income and expenses. During the year ended December 31, 2014, we recognized a net gain of $137.2 million on our commodity derivative contracts including net gains of $5.6 million associated with the settlements of commodity derivative contracts offset by $0.7 million related to the premiums paid on derivative contracts. These gains were primarily the result of the significant decreases in commodity prices during the period. During the year ended December 31, 2013, we recognized a net loss of $16.9 million on our commodity derivative contracts including net losses of $5.8 million associated with the settlements of commodity derivative contracts and $2.8 million related to the premiums paid on derivative contracts. These losses were primarily the result of increases in commodity prices during the period. During the year ended December 31, 2012, we recognized a net loss of $0.7 million on our commodity derivative contracts including net gains of $2.7 million associated with the settlements of commodity derivative contracts offset by $3.1 million related to the premiums paid on derivative contracts.

Income tax expense. For the year ended December 31, 2014, the Company recorded income tax benefit of $11.4 million. Our effective tax rate for the year ended December 31, 2014 was 34.4% as compared to a statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is related to non-deductible G&A expenses recorded during the period. For the year ended December 31, 2013, income tax expense totaled $4.0 million. Our 2013 effective rate was 12.91% compared to a statutory rate of 35% due primarily to the release of the previously recorded valuation allowance. We expect our effective tax rate going forward to be approximately 35%.

Liquidity and Capital Resources

As of December 31, 2014, we had approximately $474 million in cash and cash equivalents and a $650 million unused, available borrowing base (with a $300 million elected commitment amount) under our revolving credit facility with a group of sixteen participating banks, resulting in available liquidity of approximately $774 million, not including the additional $350 million of approved revolving credit facility borrowing base, which we elected not to accept at this time, but may be utilized subject to the satisfaction of certain conditions.

We expect to use a portion of our cash on hand and our internally generated cash flows from operations to fund our 2015 capital expenditures. The Company recently announced a new 2015 capital spending plan of approximately $600 to $650 million, a decrease from previous preliminary estimates of $1.1 to $1.2 billion. The new spending plan was approved in light of the recent, significant downward move in oil prices, both current and expectations for all of 2015. The Company believes it can fully fund its capital spending plan from cash on hand and internally generated cash flows, leaving the borrowing capacity under our Second Amended and Restated Credit Agreement unused in 2015 while still being able to modestly increase production volumes year over year. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

For a description of current and previous credit agreements along with the indentures covering our Senior Notes refer to Note 5, "Long-Term Debt."

For a description of current and previous common stock and preferred stock activity refer to Note 6, "Stockholders' Equity." In addition, in February, May and August 2014, the Company entered into exchange agreements with certain holders of the Company's Series A Convertible Perpetual Preferred Stock, and of Series B Convertible Perpetual Preferred Stock ("the Holders"), pursuant to which the Holders exchanged an aggregate of 1,161,015 shares of Series A Preferred Stock and 967,670 shares of Series B Preferred Stock (and waived their rights to any accrued and unpaid dividends thereon) for 2,963,609 shares and 2,575,046 shares of the Company's common stock, respectively.

As a result of these exchanges, the Company has reduced its cash dividend payments on its Series A Preferred Stock and Series B Preferred Stock during the year ended December 31, 2014 by $5.6 million as compared to the amount that would have been paid based on the number of shares outstanding prior to these conversions. The Company has also reduced its anticipated future cash dividend payments by a total of approximately $1.5 million each quarter.

Table of Contents

Cash Flows

Our cash flows for the years ended December 31, 2014, 2013 and 2012 are as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Cash Flow Data:			
Net cash provided by operating activities	$ 415,335	$ 189,261	$ 29,072
Net cash used in investing activities	$ (1,361,264)	$ (1,093,363)	$ (181,427)
Net cash provided by financing activities	$ 1,266,112	$ 1,007,286	$ 139,661

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $415.3 million for the year ended December 31, 2014 compared to $189.3 million and $29.1 million for the same periods in 2013 and 2012, respectively. This increase was related to the favorable impact of changes in working capital items, including higher sales volumes partially offset by the impact of lower average commodity prices between the periods. Additionally, significant non-cash items including a $213.8 million full cost ceiling impairment and DD&A expense of $338.1 million recorded during the period served to more than offset the net loss and any other reductions to operating cash flows during the period.

One of the primary sources of variability in the Company's cash flows from operating activities is fluctuations in commodity prices, the impact of which the Company partially mitigates by entering into commodity derivatives. Sales volume changes also impact cash flow. The Company's cash flows from operating activities are also dependent on the costs related to continued operations and debt service.

Net Cash Used in Investing Activities. Net cash flows used in investing activities totaled $1.4 billion for the year ended December 31, 2014 compared to $1.1 billion and $181.4 million for the same periods in 2013 and 2012, respectively. Capital expenditures for leasehold and drilling activities for the year ended December 31, 2014 totaled $791.3 million, primarily associated with bringing online 121 gross wells. We paid cash of $557.1 million for the oil and natural gas properties acquired in the Catarina acquisition. We received cash of $0.7 million and $0.5 million as final settlement for the oil and natural gas properties acquired in the Cotulla and Wycross acquisitions, respectively. In addition, we invested $14.1 million in other property and equipment. For the year ended December 31, 2013, we incurred capital expenditures of $479.9 million, primarily associated with bringing online 83 gross wells. We paid cash of approximately $623.0 million for the oil and natural gas properties acquired in the Cotulla acquisition, the TMS transaction, the Wycross acquisition as well as other less material acquisitions of oil and natural gas properties. In addition, we invested $2.1 million in computers and other equipment. Partially offsetting these costs were proceeds of $11.6 million from the sale of marketable securities. In 2012, we made capital expenditures for leasehold and drilling activities of $169.7 million, primarily associated with the drilling of 20 wells, and invested $11.6 million in marketable securities.

Net Cash Provided by Financing Activities. Net cash flows provided by financing activities totaled $1.3 billion for the year ended December 31, 2014 compared to $1.0 billion for the same period in 2013. During the year ended December 31, 2014, we received net proceeds from the issuance of common stock of $167.5 million, after deducting offering costs payable by us of $8.7 million. We also made payments of $16.3 million for dividends on our Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock. We received net proceeds of approximately $1.12 billion from the issuance of our 6.125% Notes, consisting of a face value of $1.15 billion, including the Additional 6.125% Notes which were issued at a premium to face value of $2.3 million, less debt issuance costs of $27.4 million. Other debt issuance costs for the year ended December 31, 2014 totaled $10.0 million. On May 12, 2014, the Company borrowed $100 million under the Amended and Restated Credit Agreement. The Company used proceeds from the issuance of the Original 6.125% Notes to repay the $100 million outstanding under the Amended and Restated Credit Agreement, in addition to funding a portion of the purchase price of the Catarina acquisition.

During the year ended December 31, 2013, we received net proceeds from the private placement of our Series B Convertible Perpetual Preferred Stock of approximately $216.6 million, after deducting placement agent's fees and offering costs payable by us of approximately $8.4 million. We also received net proceeds of approximately $577.0 million from the private placement of our 7.75% Notes, consisting of face value of $600 million, including the Additional 7.75% Notes which were issued at a discount to face value of $7 million, less debt issuance costs of approximately $16 million, included in the $24.1 million discussed below. During the three months ended September 30, 2013, the Company completed a public offering of common stock, and received net proceeds from this offering of approximately $241.5 million, after deducting underwriter's fees and other expenses of approximately $12.4 million. During the three months ended March 31, 2013, we borrowed $50 million under the Second Lien Credit Agreement. On May 30, 2013, we borrowed $90 million under the Original Credit Agreement. On May 31, 2013, we borrowed $96 million under our Amended and Restated Credit Agreement, and used the proceeds to repay the $90 million borrowed under our Original Credit Agreement. The outstanding borrowings under our Amended and Restated Credit Agreement and Second Lien Credit Agreement were repaid during the three months ended June 30, 2013 with proceeds from the offering of the Original 7.75% Notes. Other financing costs for the year ended December 31, 2013 included $24.1 million for debt issuance costs, $18.5 million paid for preferred stock dividends and $1.1 million paid for the purchase of common stock to settle taxes on the vesting of employee stock grants.

For the year ended December 31, 2012, net cash flows provided by financing activities totaled $139.7 million primarily due to net proceeds from our private placement of our Series A Convertible Perpetual Preferred Stock of approximately $144.5 million, after deducting the initial purchasers' discounts and commissions and offering costs payable by us of approximately $5.5 million. These net proceeds were partially offset by financing costs associated with our credit facilities of $2.7 million and preferred dividends paid of $2.1 million.

Commitments and Contractual Obligations

Refer to Note 14, "Commitments and Contingencies" for a description of lawsuits pending against the Company.

As of December 31, 2014, our contractual obligations included our Senior Notes, interest expense on our Senior Notes, asset retirement obligations, rent expense for our corporate offices and other long term lease payments. The material changes in our contractual obligations during the year ended December 31, 2014 included: (i) the issuance of our 6.125% Notes and the associated interest expense, (ii) the recognition of asset retirement obligations related to acquired properties and drilling activity, (iii) the lease of corporate office space, (iv) the lease of land owned by the Calhoun Port Authority and

Table of Contents

(v) the lease of the promotional ranch managed by the Company. The following table summarizes our contractual obligations as of December 31, 2014 (in thousands):

	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Notes	$	$	$	$ 1,750,000	$ 1,750,000
Interest expense(1)	116,631	233,875	233,875	316,281	900,663
Asset retirement obligations(2)				25,694	25,694
Office rent(3)	3,952	10,345	10,680	29,776	54,754
Other leases(4)	1,792	3,583	3,583	6,714	15,672
Total	$ 122,375	$ 247,803	$ 248,138	$ 2,128,466	$ 2,746,783

---

(1) Represents estimated interest payments that will be due under the $600 million 7.75% Notes and $1,150 million 6.125% Notes that will mature on June 15, 2021 and January 15, 2023, respectively.

(2) Amounts represent the present value of our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 12 Asset Retirement Obligations in the Notes to the Consolidated Financial Statements under Item 8 of this Form 10-K.

(3) Represents payments due for leasing corporate office space in Houston, TX. The lease began on November 1, 2014 and continues until March 31, 2025.

(4) Represents payments due for a ground lease agreement for land owned by the Calhoun Port Authority which commenced on August 25, 2014 and continues until August 25, 2024. Also represents payments due for an acreage lease agreement for a promotional ranch managed by the Company in Kenedy County, TX which commenced on March 1, 2014 and continues until February 28, 2024.

In addition, in connection with the TMS transaction, the Company has committed to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI. In the event that we did not fulfill in a timely manner our obligations with regard to the initial TMS well commitment we would have re-assigned the working interests acquired from SR. As of the date of this filing, we have met our initial well carry and exercised our right to continue drilling within the AMI and earn full rights to all acreage by carrying SR for an additional 3 gross (1.5 net) TMS wells. We expect to meet our well carry commitments for the full 6 gross (3 net) TMS wells in 2015.

In connection with the Catarina acquisition, the 77,000 acres of undeveloped acreage that were included in the acquisition are subject to a continuous drilling obligation. Such drilling obligation requires us to drill (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120-day period in order to maintain rights to any future undeveloped acreage. Up to 30 wells drilled in excess of the minimum 50 wells in a given annual period can be carried over to satisfy part of the 50 well requirement in the subsequent annual period on a well for well basis. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include the drilling of at least the minimum number of wells required to maintain access to such undeveloped acreage.

The Company's ground lease with the Calhoun Port Authority is terminable upon 180 days written notice by the Company to the lessor in addition to a $1 million termination payment. In connection with the lease agreement for acreage in Kenedy County, Texas, there is a contractual requirement for the Company to spend a minimum of $4 million to make permanent improvements over the ten year life of the lease. The lease agreement does not specify the timing for such improvements to be made within the lease term. The Company has the right to terminate its lease obligation at any time without penalty with six months advanced written notice and payment of any accrued leasehold expenses.

Off-Balance Sheet Arrangements

As of December 31, 2014, we did not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements that have been prepared in accordance with U.S. GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 2, "Basis of Presentation and Summary of Significant Accounting Policies." When we prepare our financial statements, we review our estimates, including those related to oil, NGL and natural gas revenues, oil and natural gas properties, oil, NGL and natural gas reserves, fair value of derivative instruments, abandonment liabilities, income taxes, commitments and contingencies, depreciation, depletion and amortization, and full cost ceiling calculation. Our estimates are based on historical experience and various assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties

The Company's oil and natural gas properties are accounted for using the full cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Once evaluated, these costs, as well as the estimated costs to retire the assets, are included in the amortization base and amortized to depletion expense using the units-of-production method. Depletion is calculated based on estimated proved oil and natural gas reserves. Proceeds from the sale or disposition of oil and natural gas properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated quantities of proved reserves.

Full Cost Ceiling Test Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and natural gas properties are subject to a full cost ceiling limitation. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. In accordance with SEC rules, the oil and natural gas prices used to calculate the full cost ceiling are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12- month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Prices are adjusted for "basis" or location differentials. Prices are held constant over the life of the reserves. If unamortized costs capitalized within the cost pool exceed the ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off are not reinstated for any subsequent increase in the cost center ceiling. During the year ended December 31, 2014, the Company recorded a full cost ceiling test impairment before income taxes of $213.8 million. No impairment expense was recorded for the years ended December 31, 2013 and 2012. If the unweighted arithmetic average price of oil, NGLs and natural gas as of the first day of each month for the 12-month period ended December 31, 2014 had been 10% lower while all other

Table of Contents

factors remained constant, our ceiling amount related to our net book value of oil and natural gas properties would have been reduced by approximately $651.2 million and our full cost ceiling impairment would have increased by approximately $651.2 million before income taxes.

Depreciation, depletion, amortization and accretion DD&A is provided using the units-of-production method based upon estimates of proved oil, NGL and natural gas reserves with oil, NGL and natural gas production being converted to a common unit of measure based upon their relative energy content. All capitalized costs of oil and natural gas properties, including the estimated future costs to develop proved reserves, are amortized using the units-of-production method based on total proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Once the assessment of unproved properties is complete and when major development projects are evaluated, the costs previously excluded from amortization are transferred to the full cost pool and amortization begins. The amortizable base includes estimated future development costs and where significant, dismantlement, restoration and abandonment costs, net of estimated salvage value.

In arriving at depletion rates under the units-of-production method, the quantities of recoverable oil and natural gas reserves are established based on estimates made by internal and third party geologists and engineers, which require significant judgment as does the projection of future production volumes and levels of future costs, including future development costs. In addition, considerable judgment is necessary in determining when unproved properties become impaired and in determining the existence of proved reserves once a well has been drilled. All of these judgments may have significant impact on the calculation of depletion and impairment expense. At December 31, 2014, a 10% positive revision to proved reserves would decrease the depletion rate by approximately $2.60 per boe and a 10% negative revision to proved reserves would increase the depletion rate by approximately $3.16 per boe. Further, a 10% increase or decrease in estimated future development costs would increase or decrease the depletion rate by approximately $1.20 per boe at December 31, 2014.

Unproved Properties Costs associated with unproved properties and properties under development are excluded from the full cost amortization base until the properties have been evaluated. Additionally, the costs associated with seismic data, leasehold acreage, and wells currently drilling are also initially excluded from the amortization base. Unproved properties are identified on a project basis, with a project being an area in which significant leasehold interests are acquired within a contiguous area. Unproved properties are reviewed periodically by management and transferred into the full cost pool subject to amortization when management determines that a project area has been evaluated through drilling operations or a thorough geologic evaluation.

Oil and Natural Gas Reserves

The Company's most significant estimates relate to its proved oil, NGL and natural gas reserves. The estimates of oil, NGL and natural gas reserves as of December 31, 2014, 2013 and 2012 are based on reports prepared by a third party engineering firm, Ryder Scott.

Estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Ryder Scott has historically prepared a reserve and economic evaluation of the Company's properties, utilizing information provided to it by management and other information available, including information from the operators of the property.

The standards of the FASB and rules of the SEC permit the use of new technologies to determine proved reserve estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. These rules allow, but do not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC.

In addition, the disclosure guidelines require companies to report oil and natural gas reserves using an average price based upon the prior 12-month first-day-of-the-month price rather than a period-end price.

Reserves and their relation to estimated future net cash flows impact the depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The reserve estimates and the projected cash flows derived from these reserve estimates are prepared in accordance with SEC guidelines. The independent engineering firm noted above adheres to these guidelines when preparing their reserve reports. The accuracy of the reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered. Additionally, with other factors held constant, if the commodity prices used in our reserve report as of December 31, 2014 had decreased by 10%, then the standardized measure of our estimated proved reserves as of that date would have decreased by approximately $423 million, from approximately $1,781 million to approximately $1,358 million.

Asset Retirement Obligations

Asset retirement obligations represent the present value of the estimated cash flows expected to be incurred to plug, abandon and remediate producing properties, excluding salvage values, at the end of their productive lives in accordance with applicable laws. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, well life, inflation and credit-adjusted risk free rate. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized over the useful life of the related asset. Upon settlement of the liability, any gain or loss is treated as an adjustment to the full cost pool.

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities arise from the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary difference and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce the deferred tax asset to the amount more likely than not to be recovered.

Additionally, the Company is required to determine whether it is more likely than not (a likelihood of more than 50%) that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position in order to record any financial statement benefit. If that step is satisfied, then the Company must measure the tax position to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that has greater than a 50% likelihood of being realized upon ultimate settlement. Any interest or penalties would be recognized as a component of income tax expense.

Table of Contents

The Company applies significant judgment in evaluating its tax positions and estimating its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact the Company's financial position, results of operations and cash flows. The Company does not have any material uncertain tax positions during the years ended December 31, 2014 or 2013.

Stock-Based Compensation

The Company records stock-based compensation expense for awards granted to its directors (for their services as directors) in accordance with the provisions of ASC 718, "Compensation Stock Compensation." Stock-based compensation expense for these awards is based on the grant-date fair value and recognized over the vesting period using the straight-line method.

Awards granted to employees of the Sanchez Group (including those employees of the Sanchez Group who also serve as the Company's officers) and consultants in exchange for services are considered awards to non-employees and the Company records stock-based compensation expense for these awards at fair value in accordance with the provisions of ASC 505-50, "Equity-Based Payments to Non-Employees." For awards granted to non-employees, the Company records compensation expense equal to the fair value of the stock-based award at the measurement date, which is determined to be the earlier of the performance commitment date or the service completion date. Compensation expense for unvested awards to non-employees is revalued at each period end and is amortized over the vesting period of the stock-based award. Stock-based payments are measured based on the fair value of the equity instruments granted, as it is more determinable than the value of the services rendered.

For the restricted stock awards granted to non-employees, stock-based compensation expense is based on fair value re-measured at each reporting period and recognized over the vesting period using the straight-line method. Compensation expense for these awards will be revalued at each period end until vested.

Revenue Recognition

Oil, NGL and natural gas sales are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred, and collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline, railcar or truck, or a tanker lifting has occurred. The sales method of accounting is used for oil, NGL and natural gas sales such that revenues are recognized based on our share of actual proceeds from the oil, NGLs and natural gas sold to purchasers. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production "in-kind" and, in doing so, take more or less than their respective entitled percentage.

Derivative Instruments

At times we may utilize derivative instruments to manage our exposure to fluctuations in the underlying commodity prices for the products sold by us. The carrying amount of derivative assets and liabilities is reported on the balance sheet at the estimated fair value of the derivative instruments. Our management sets and implements all of our hedging policies, including volumes, types of instruments and counterparties, on a monthly basis. These derivative transactions are not designated as cash flow hedges. Accordingly, these derivative contracts are marked-to-market and any changes in the estimated value of derivative contracts held at the balance sheet date are recognized in the statement of operations as net gains (losses) on commodity derivatives.

Table of Contents

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

We are exposed to market risk, including the effects of adverse changes in commodity prices and, potentially, interest rates as described below.

The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, NGLs and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, NGL and natural gas production. Realized pricing is primarily driven by the prevailing market prices applicable to our oil, NGL and natural gas production. Pricing for oil, NGL and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, NGL and natural gas production depend on many factors outside of our control, such as the strength of the global economy.

To reduce the impact of fluctuations in oil and natural gas prices on the Company's revenues, or to protect the economics of property acquisitions, the Company periodically enters into derivative contracts with respect to a portion of its projected oil and natural gas production through various transactions that fix or, through options, modify the future prices to be realized. These transactions may include price swaps whereby the Company will receive a fixed price for its production and pay a variable market price to the contract counterparty. Additionally, the Company may enter into collars, whereby it receives the excess, if any, of the fixed floor over the floating rate or pays the excess, if any, of the floating rate over the fixed ceiling price. In addition, the Company enters into option transactions, such as puts or put spreads, as a way to manage its exposure to fluctuating prices. The Company further uses enhanced swaps for a portion of its commodity price hedging activities. An enhanced swap is a product created by simultaneously selling an out of the money put and using the premium value from the sale to modify or "enhance" the value of a swap executed at the same time. The transaction provides an absolute minimum price at the enhanced swap strike price until the put strike price level is reached at which point the Company receives the market price plus the difference between the enhanced swap price and the put strike price. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never the Company's intention to enter into derivative contracts for speculative trading purposes. Please refer to Note 10, "Derivative Instruments" for a description of all of our derivatives covering anticipated future production as of December 31, 2014.

At December 31, 2014, the fair value of our commodity derivative contracts was a net asset of $123.3 million. A 10% increase in the oil and natural gas index prices above the December 31, 2014 prices would result in a decrease in the fair value of our commodity derivative contracts of $29.6 million; conversely, a 10% decrease in the oil and natural gas index prices would result in an increase of $26.6 million.

In February 2015, the Company modified certain of its crude oil enhanced swap and three-way collar transactions to create crude oil swaps on a costless transactional basis. The modification to a fixed price eliminates downside risk, preserves value and provides the Company with greater certainty in crude oil pricing for the remainder of 2015. We have commodity derivative contracts in place covering approximately 60% of the mid-point of our total estimated production for 2015.

Table of Contents

Interest Rate Risk

As of December 31, 2014, no amounts were outstanding under our Second Amended and Restated Credit Agreement. Our 7.75% Notes bear a fixed interest rate of 7.75% with an expected maturity date of June 15, 2021, and we had $600 million outstanding as of December 31, 2014. Our 6.125% Notes bear a fixed interest rate of 6.125% with an expected maturity date of January 15, 2023, and we had $1.15 billion outstanding as of December 31, 2014. We currently do not have any interest rate derivative contracts in place. If we incur significant debt with a risk of fluctuating interest rates in the future, we may enter into interest rate derivative contracts on a portion of our then outstanding debt to mitigate the risk of fluctuating interest rates.

Item 8. *Financial Statements and Supplementary Data*

The information required by this Item is included in this report as set forth in the "Index to Consolidated Financial Statements" on page F-1 and is incorporated by reference herein.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Rule 13a-15 promulgated pursuant to the Exchange Act. Based upon that evaluation, and as described below, management identified a material weakness in the Company's internal control over financial reporting. Internal control over financial reporting is an integral component of the Company's disclosure controls and procedures. Solely as a result of this material weakness, the Company's Chief Executive Officer and Chief Financial Officer concluded that, as of the end of the period covered by this report, the Company's disclosure controls and procedures were not effective as of December 31, 2014 at the reasonable assurance level.

Management concluded that the consolidated financial statements included in this Annual Report on Form 10-K fairly present, in all material respects, the financial position of the Company at December 31, 2014 and 2013 and the consolidated results of operations and cash flows for each of the three years in the period ended December 31, 2014 in conformity with U.S. GAAP.

Management's Annual Report on Internal Control Over Financial Reporting and Attestation Report of the Registered Public Accounting Firm

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

Table of Contents

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2014. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control Integrated Framework (2013). Based on this assessment and such criteria, our management concluded that our internal control over financial reporting was not effective as of December 31, 2014 solely as a result of the material weakness discussed below. Further, we have determined that these control deficiencies existed with respect to certain aspects of our historical financial reporting and, accordingly, we have concluded that our prior disclosures regarding the sufficiency of our disclosure controls may not have been correct.

In connection with the preparation of the Company's year-end reserve report, the Company has a process for estimating future development costs that relies on management guidance including historical cost structures and approved future budgets. Controls over the estimation and review of future development costs were not designed appropriately as the estimates of future development costs in the reserve report were not adequately reduced for incurred and accrued current period drilling costs, and future development costs were over-estimated by approximately $85 million. This resulted in a control deficiency related to the estimation of future development costs included in the reserve report as of December 31, 2014.

Estimated future development costs impact the accuracy of the full cost ceiling test for impairment and the calculated impairment and depletion expense amounts. This control deficiency failed to detect an overstatement of approximately $85 million in future development costs included in our 2014 reserve report. If the overstatement of future development costs was not corrected, the Company would have overstated depletion expense by approximately $2 million and overstated impairment expense by approximately $127.2 million, before income tax, on the Company's financial statements as of and for the three months and the year ended December 31, 2014. Management concluded that the identified control deficiency constituted a material weakness and is taking steps to remediate the deficiency as described below.

BDO USA, LLP, an independent registered public accounting firm ("BDO"), has issued its report on the effectiveness of the Company's internal control over financial reporting at December 31, 2014. The report from BDO is included in this Item under the heading "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting."

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the three months ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Plan of Remediation of Material Weakness

Management plans to implement a number of steps to remediate the material weakness discussed above and improve its internal control over financial reporting related to the process for estimating future development costs on the reserve report. Specifically, the following are planned:

(i) required meetings near the end of each quarter end with accounting, operations, and reserves engineering personnel to communicate the current drilling status, future drilling plans, and current estimated future development costs by development area; and

(ii) enhance the detail of review activities on the future development costs in the reserve report during the financial statement close process.

Management is committed to improving the Company's internal control processes and has developed and presented to the Audit Committee a plan and timetable for the implementation of the

Table of Contents

remediation measures described above and will meet frequently with the Audit Committee to monitor the status of remediation activities. Management believes that the measures described above should remediate the material weakness identified and strengthen the Company's internal control over financial reporting related to the process for estimating future development costs on the reserve report. As the Company continues to evaluate and improve its internal control over financial reporting related to the process for estimating future development costs on the reserve report, additional measures to remediate the material weakness or modifications to certain of the remediation procedures described above may be necessary. The Company expects to complete the required remedial actions during 2015. However, the Company cannot provide any assurance that these remediation efforts will be successful or that its internal control over financial reporting will be effective as a result of these efforts.

Table of Contents

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

Board of Directors and Stockholders
Sanchez Energy Corporation
Houston, Texas

We have audited Sanchez Energy Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Sanchez Energy Corporation's 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 "Item 9A, 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. A material weakness regarding management's failure to design and maintain controls over future development costs included in the reserve report as of December 31, 2014 has been identified and described in management's assessment. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2014 financial statements, and this report does not affect our report dated March 2, 2015 on those financial statements.

In our opinion, Sanchez Energy Corporation did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

Table of Contents

We do not express an opinion or any other form of assurance on management's statements referring to any corrective actions taken by the company after the date of management's assessment.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Sanchez Energy Corporation as of December 31, 2014 and 2013, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014 and our report dated March 2, 2015 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Houston, Texas
March 2, 2015

Table of Contents

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Information regarding our directors, executive officers and certain corporate governance items will be included in an amendment to this Form 10-K or in the proxy statement for the 2015 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2014, and is incorporated by reference to this report.

Item 11. ***Executive Compensation***

Information regarding executive compensation will be included in an amendment to this Form 10-K or in the proxy statement for the 2015 annual meeting of stockholders and is incorporated by reference to this report.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Information regarding beneficial ownership and management and related stockholder matters will be included in an amendment to this Form 10-K or in the proxy statement for the 2015 annual meeting of stockholders and is incorporated by reference to this report.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Information regarding certain relationships and related transactions and director independence will be included in an amendment to this Form 10-K or in the proxy statement for the 2015 annual meeting of stockholders and is incorporated by reference to this report.

Item 14. ***Principal Accountant Fees and Services***

Information regarding principal accounting fees and services will be included in an amendment to this Form 10-K or in the proxy statement for the 2015 annual meeting of stockholders and is incorporated by reference to this report.

Table of Contents

GLOSSARY OF SELECTED OIL AND NATURAL GAS TERMS

The following includes a description of the meanings of some of the oil and natural gas industry terms used in this Annual Report on Form 10-K. The definitions "analogous reservoir," "development costs," "development project," "development well," "economically producible," "exploratory well," "field," "possible reserves," "probable reserves," "production costs," "proved area," "reservoir," "resources," and "unproved properties" have been excerpted from the applicable definitions contained in Rule 4-10(a) of Regulation S-X.

American Petroleum Institute ("API") gravity: A system of classifying oil based on its specific gravity, whereby the greater the gravity, the lighter the oil.

analogous reservoir: Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

basin: A large depression on the earth's surface in which sediments accumulate.

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

bcf: One billion cubic feet of natural gas.

black oil: A quality of oil with an API gravity of 40° or less and with a gas-to-oil ratio of 500 cubic feet per barrel or less.

bo: 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

boe: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six mcf of natural gas to one bo of oil.

boe/d: One boe per day.

bopd: One bo per day.

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.

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

developed acreage: The number of acres that are allocated or assignable to producing wells or wells capable of production.

development costs: Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves; (ii) drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly; (iii) acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.

development project: A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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.

differential: An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

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

economically producible: The term economically producible, as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

exploitation: A development or other project that may target proven or unproven reserves (such as probable or possible reserves), but that generally has a lower risk than that associated with exploration projects.

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

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

gross acres or gross wells: The total acres or wells, as the case may be, in which we have working interest.

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

independent exploration and production company: A company whose primary line of business is the exploration and production of crude oil and natural gas.

LLS: Louisiana light sweet crude.

mbbl: One thousand bbl.

mbo: One thousand bo.

mboe: One thousand boe.

mcf: One thousand cubic feet of natural gas.

mmbo: One million bo.

Table of Contents

mmbbl: One million bbl.

mmboe: One million boe.

mmbtu: One million British thermal units.

mmcf: One million cubic feet of natural gas.

net acres or net wells: Gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

net production: Production that is owned by us less royalties and production due others.

net revenue interest: A working interest owner's gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

NG: Natural gas.

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: New York Mercantile Exchange.

operator: The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

possible reserves: Additional reserves that are less certain to be recovered than probable reserves.

probable reserves: Additional reserves that are less certain to be recovered than proved reserves but that, in sum with proved reserves, are as likely as not to be recovered.

production costs: Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

productive well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

proved area: The part of a property to which proved reserves have been specifically attributed.

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

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

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

realized price: The cash market price less all expected quality, transportation and demand adjustments.

recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Table of Contents

reserve: That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

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

resources: Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

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

standardized measure: The present value of estimated future after tax net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions.

trend: A geographic area with hydrocarbon potential.

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 and natural gas regardless of whether such acreage contains proved reserves.

unproved properties: Properties with no proved reserves.

volatile oil: A quality of oil with an API gravity greater than 40° and with a gas-to-oil ratio of greater than 500 cubic feet per barrel.

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

working interest: An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

workover: Operations on a producing well to restore or increase production.

WTI: West Texas Intermediate crude.

Table of Contents

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

a. The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The following exhibits are filed or furnished with this Annual Report on Form 10-K or incorporated by reference:

Exhibit No.	Description of Exhibit
2.1	Contribution, Conveyance and Assumption Agreement, dated as of December 19, 2011, by and between Sanchez Energy Partners I, LP and Sanchez Energy Corporation (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on December 23, 2011, and incorporated herein by reference).
2.2	Contribution Agreement, dated November 8, 2011, by and between Ross Exploration, Inc. and Sanchez Energy Corporation (filed as Exhibit 2.2 to Amendment No. 3 to the Company's registration statement on Form S-1 (File. No. 333-176613) on November 25, 2011, and incorporated herein by reference).
2.3**	Purchase and Sale Agreement by and between Hess Corporation, as Seller, and Sanchez Energy Corporation, as Buyer, dated as of March 18, 2013 (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on June 3, 2013, and incorporated herein by reference).
2.4**	Purchase and Sale Agreement by and between Altpoint Sanchez Holdings, LLC, as Seller, and Sanchez Energy Corporation, as Buyer, dated as of August 7, 2013 (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on August 13, 2013, and incorporated herein by reference).
2.5**	Purchase and Sale Agreement by and between Rock Oil Company, LLC, as Seller, and SN Cotulla Assets, LLC, as Buyer, dated as of September 6, 2013 (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on September 9, 2013, and incorporated herein by reference).
2.6	