Sanchez Energy Corp
Form 10-K
March 01, 2019
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10 K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
or
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: 1 35372

Sanchez Energy Corporation

(Exact name of Registrant as specified in its charter)

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

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

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Rights to purchase Series C Junior Participating Preferred 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 No

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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 No

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes No

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.

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company", and "emerging growth company" in Rule 12b 2 of the Exchange Act.

Large accelerated filer Accelerated filer Non accelerated filer Smaller reporting company

Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

Aggregate market value of the voting and non voting common equity held by non affiliates of Registrant as of June 30, 2018: $284,800,499

Number of shares of Registrant's common stock outstanding as of February 26, 2019: 95,866,121.

Documents Incorporated By Reference:

Portions of the Registrant's definitive proxy statement for its 2019 Annual Meeting of Stockholders or an amendment to this Form 10-K, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2018, are incorporated by reference into Part III of this report for the year ended December 31, 2018.

Table of Contents

SANCHEZ ENERGY CORPORATION

FORM 10 K

FOR THE YEAR ENDED DECEMBER 31, 2018

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,” “forecast,” “budget,” “guidance,” “pr “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, service our debt and other obligations and repay or otherwise refinance such obligations when due or at maturity, operational and commercial benefits of our partnerships, expected benefits from acquisitions, including the Comanche Acquisition (defined below), and our strategic relationship with Sanchez Midstream Partners LP (“SNMP”) 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:

· the timing and extent of changes in prices of, and demand for, crude oil and condensate, natural gas liquids (“NGLs”), natural gas and related commodities;

· our ability to successfully execute our business and financial strategies;

· our ability to comply with the financial and other covenants in our debt instruments, to repay our debt, and to address our liquidity needs, particularly if commodity prices remain volatile and/or depressed;

· the extent to which we are able to engage in successful strategic alternatives to improve our balance sheet and satisfy our obligations under our debt instruments;

· the extent to which we are able to pursue drilling plans and acquisitions that are successful in maintaining and economically developing our acreage, producing and replacing reserves and achieving anticipated production levels;

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our ability to successfully integrate our various acquired assets into our operations, realize the benefits of those acquisitions, fully identify and address existing and potential issues or liabilities and accurately estimate reserves, production and costs with respect to such assets;

- 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, debt service and other funding requirements through internally generated cash flows, asset sales and other activities;

- the extent to which our listing in the over-the-counter market rather than on a national securities exchange will impair our access to the equity markets and ability to obtain financing;

- our ability to utilize the services, personnel and other assets of Sanchez Oil & Gas Corporation (“SOG”) pursuant to an existing services agreement (the “Services Agreement”);

Table of Contents

- SOG's ability to retain personnel and other resources to perform its obligations under the Services Agreement;

- the realized benefits of our partnerships and joint ventures, including our transactions with SNMP and our partnership with affiliates of The Blackstone Group, L.P. ("Blackstone");

- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may, therefore, be imprecise;

- the effectiveness of our internal control over financial reporting;

- the extent to which we can optimize reserve recovery and economically develop our properties utilizing horizontal and vertical drilling, advanced completion technologies, hydraulic stimulation and other techniques;

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

- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;

- the availability, creditworthiness and performance of our counterparties, including financial institutions, operating partners and other parties;

- the extent to which requests for credit assurances, or minimum volume commitments or "take-or-pay" obligations in excess of our oil and natural gas deliveries to, or transportation needs from, our contractual counterparties could have a material adverse effect on our business, financial condition and results of operations;

- competition in the oil and natural gas exploration and production industry generally and with respect to the marketing of oil, natural gas and NGLs, acquisition of leases and properties, attraction and retention of employees and other personnel, procurement of equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;

- the extent to which our production, revenue and cash flow from operating activities are concentrated in a single geographic area;

- 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 and pricing of oil and natural gas;

- the extent to which third parties operate our oil and natural gas properties successfully and economically;

- our ability to manage the financial risks where we share with more than one party the costs of drilling, equipping, completing and operating wells, including with respect to the Comanche Assets;

- the use of competing energy sources, the development of alternative energy sources and potential economic implications and other effects therefrom;

- results of litigation filed against us or other legal proceedings or out-of-court contractual disputes to which we are party;

Table of Contents

- the extent to which we incur uninsured losses and liabilities or losses and liabilities in excess of our insurance coverage, including losses related to sabotage, terrorism or other malicious intentional acts (including cyber-attacks) that disrupt operations;

- 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, regulations, restrictions and guidelines with respect to derivatives, hedging activities and commercial lending standards; 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. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

Item 1. Business

Overview

Sanchez Energy Corporation (together with our consolidated subsidiaries, "Sanchez Energy," 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 acquisition and development of oil and natural gas resources in the onshore United States. We are currently focused on the horizontal development of significant resource potential from the Eagle Ford Shale in South Texas, and we also hold other producing properties and undeveloped acreage, including in the Tuscaloosa Marine Shale ("TMS") in Mississippi and Louisiana which offers potential future development opportunities. As of December 31, 2018, we have assembled approximately 472,000 gross leasehold acres (271,000 net acres) in the Eagle Ford Shale, where we plan to invest the majority of our 2019 capital budget. We continually evaluate opportunities to manage our overall portfolio, which may include the acquisition of additional properties in the Eagle Ford Shale or other producing areas and, from time to time, the divestiture of non-core assets. Our successful acquisition of such properties will depend on the circumstances and the financing alternatives available to us at the time we consider such opportunities. However, at this time we are primarily focused on lowering cash costs across our business and reducing our financial leverage, with an objective of maximizing our liquidity position and improving our balance sheet. We are also pursuing a number of strategic alternatives to better align our capital structure with the current low commodity price environment. 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.”

Table of Contents

Listed below is a table of our significant acquisition and divestiture transactions since January 1, 2016:

Transaction	Closing Date	Effective Date	Core Area	Approximate Net Acreage	Disposition/ (Purchase) Price(1)
Javelina Disposition	9/19/2017	8/1/2017	Eagle Ford	68,000	$ 105
Marquis Disposition	6/15/2017	1/1/2017	Eagle Ford	21,000	$ 50
Comanche Acquisition(2)	3/1/2017	7/1/2016	Eagle Ford, Pearsall	76,000	$ (1,044)
Cotulla Disposition	12/14/2016	6/1/2016	Cotulla, Eagle Ford	15,000	$ 167
Carnero Processing Disposition	11/22/2016	11/22/2016	N/A	N/A	$ 56
Production Asset Transaction	11/22/2016	7/1/2016	Palmetto and Cotulla, Eagle Ford	N/A	$ 26
Carnero Gathering Disposition	7/5/2016	7/5/2016	N/A	N/A	$ 37

(1) Prices are in millions and reflect any purchase price adjustments.
(2) Amounts shown for acreage and purchase price relate only to the SN Comanche Assets (defined below).

Javelina Disposition

On September 19, 2017, the Company, through its wholly owned subsidiary, SN Cotulla Assets, LLC (“SN Cotulla”), sold approximately 68,000 net undeveloped acres in the Eagle Ford Shale located in La Salle and Webb counties, Texas to Vitruvian Exploration IV, LLC for an adjusted purchase price of $105 million in cash (the “Javelina Disposition”). Consideration received from the Javelina Disposition was based on an August 1, 2017 effective date.

Marquis Disposition

On June 15, 2017, the Company, through its wholly owned subsidiary, SN Marquis LLC, sold approximately 21,000 net acres in the Eagle Ford Shale located in Fayette and Lavaca counties, Texas to Lonestar Resources US, Inc. (“Lonestar”) for an adjusted purchase price of approximately $44.0 million in cash and approximately $6.0 million in Lonestar’s Series B Convertible Preferred Stock, valued as of the closing date, which subsequently converted into 1.5 million shares of Lonestar’s Class A Common Stock (the “Marquis Disposition”). Consideration received from the Marquis Disposition was based on a January 1, 2017 effective date.

Comanche Acquisition

On March 1, 2017, the Company, through two of its subsidiaries, SN EF UnSub, LP ("SN UnSub") and SN EF Maverick, LLC ("SN Maverick"), along with Gavilan Resources, LLC ("Gavilan"), an entity controlled by The Blackstone Group, L.P., completed the acquisition of approximately 318,000 gross (155,000 net) acres comprised of 252,000 gross (122,000 net) Eagle Ford Shale acres and 66,000 gross (33,000 net) acres of deep rights only, which includes the Pearsall Shale, representing an approximate 49% average working interest therein (the "Comanche Assets") from Anadarko E&P Onshore LLC and Kerr-McGee Oil and Gas Onshore LP (together, "Anadarko") for an adjusted purchase price of approximately $2.1 billion in cash (the "Comanche Acquisition"). Pursuant to the purchase and sale agreement entered into in connection with the Comanche Acquisition, (i) SN UnSub paid approximately 37% of the purchase price (including with a $100 million cash contribution from other Company entities); (ii) SN Maverick paid approximately 13% of the purchase price; and (iii) Gavilan paid 50% of the purchase price. In the aggregate, SN UnSub and SN Maverick acquired half of the Comanche Assets (50% and 0%, respectively, of the estimated total proved developed producing reserves ("PDPs"), 20% and 30%, respectively, of the estimated total proved developed non-producing reserves ("PDNPs"), and 20% and 30%, respectively, of the estimated total proved undeveloped reserves ("PUDs")) (the "SN Comanche Assets"). Gavilan acquired the remaining half of the Comanche Assets (50% of the estimated total PDPs, PDNPs and PUDs). The Comanche Assets are primarily located in the Western Eagle Ford, contiguous with our existing acreage, and significantly expanded our asset base and production. The effective date of the Comanche Acquisition was July 1, 2016.

Table of Contents

Cotulla Disposition

On December 14, 2016, SN Cotulla sold approximately 15,000 net acres located in Dimmit, Frio, La Salle, Zavala and McMullen counties, Texas (the “Cotulla Assets”) to Carrizo (Eagle Ford) LLC for an adjusted purchase price of approximately $153.5 million, subject to normal and customary post-closing adjustments (the “Cotulla Disposition”). Consideration received from the Cotulla Disposition was based on a June 1, 2016 effective date. During 2017, two additional closings occurred and final settlement adjustments were recorded to the purchase price, which resulted in total aggregate consideration of approximately $167.4 million in cash.

Carnero Processing Disposition

On November 22, 2016, the Company, through SN Midstream, LLC (“SN Midstream”), a wholly-owned subsidiary of the Company, sold its membership interests in Carnero Processing, LLC (“Carnero Processing”), a joint venture that is operated and 50% owned by Targa Resources Corp. (NYSE: TRGP) (“Targa”), to SNMP for an initial payment of approximately $55.5 million in cash and the assumption by SNMP of remaining capital commitments to Carnero Processing which were estimated on the transaction closing date to be approximately $24.5 million (the “Carnero Processing Disposition”). Carnero Processing merged with Carnero Gathering (defined below), and Carnero Gathering was renamed Carnero G&P through the Carnero G&P Transaction (both as defined in “Item 8. Financial Statements and Supplementary Data —Note 10, Related Party Transactions”). The Carnero Processing Disposition purchase price was determined through arm’s length negotiations between the Company and SNMP, including independent committees of both entities.

Production Asset Transaction

On November 22, 2016, the Company, through two of its wholly-owned subsidiaries, SN Cotulla and SN Palmetto, LLC (“SN Palmetto”), completed the sale of certain non-core producing oil and natural gas assets, located in South Texas, to SNMP for an adjusted purchase price of approximately $24.2 million in cash (the “Production Asset Transaction”). The Production Asset Transaction included working interests in 23 producing Eagle Ford wellbores in Dimmit, La Salle and Zavala counties, together with escalating working interests in an additional 11 producing wellbores in the Palmetto Field in Gonzales County, Texas. The effective date of the Production Asset Transaction was July 1, 2016. The purchase price was determined through arm’s length negotiations between the Company and SNMP, including independent committees of both entities.

Carnero Gathering Disposition

On July 5, 2016, the Company, through SN Midstream, sold its membership interests in Carnero Gathering, LLC ("Carnero Gathering"), a joint venture that is operated and 50% owned by Targa, to SNMP for a purchase price of approximately $37.0 million in cash and the assumption by SNMP of remaining capital commitments to Carnero Gathering, which were estimated on the transaction closing date to be approximately $7.4 million (the "Carnero Gathering Disposition"). In connection with the Carnero G&P Transaction, Carnero Processing merged with Carnero Gathering, and Carnero Gathering was renamed Carnero G&P. See "Item 8. Financial Statements and Supplementary Data —Note 10, Related Party Transactions" for additional information. Further, SNMP is required to pay the Company a monthly "earnout" based on natural gas received at the Raptor Gas Processing Facility ("Raptor Processing Facility") from the Company and other parties. The purchase price was determined through arm's length negotiations between the Company and SNMP, including independent committees of both entities.

Our Long Term Business Strategies

Our primary business objective is to develop our resource base in a manner that maximizes our capital efficiency and financial flexibility while generating an attractive return on investment. Our long term business strategy is

Table of Contents

focused on developing oil, natural gas and NGL reserves from the Eagle Ford Shale as well as other activities that enhance or support our upstream production operations. Key elements of our long term business strategy include:

· Maintain operational flexibility for the efficient development of our Eagle Ford Shale leasehold positions. We intend to efficiently drill and develop our acreage position to maximize the value of our resource potential, while we maintain operational flexibility to control the extent and timing of our capital expenditures. At December 31, 2018, approximately 53% of our proved reserves were PUDs, and we had 947 net producing wells and had identified over 2,125 net locations for future drilling in the Eagle Ford Shale. In 2018 we invested approximately $593 million in capital expenditures to drill and complete approximately 100 wells. For 2019, in light of the downturn in commodity prices, we have elected to significantly reduce our capital expenditures budget to approximately $100 million to $150 million for development and optimization activities in our core areas. We seek to remain flexible in our business strategy to make changes to this estimated capital budget as the commodity markets and our overall financial and business position evolve over time.

· Enhance returns by focusing on operational and cost efficiencies. We are focused on the continued improvement of our operating strategies and have significant experience in successfully converting early stage resource opportunities into cost efficient development projects. We believe the magnitude and concentration of the acreage within our core areas provide us with the opportunity to capture economies of scale, including the optionality to directly source goods and services directly from manufacturers, drill multiple wells from a single pad, utilize centralized production and fluid handling facilities and implement a line-management approach to improve efficiencies in drilling and completions. In addition, we focus on midstream and other projects that serve our production and improve our access to end markets, ultimately enhancing our realized prices.

· Adopt and employ leading drilling and completion techniques. We are focused on enhancing our drilling and completion techniques to maximize the recovery of our reserves. Industry methods with respect to asset development have evolved significantly over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through technological and other advancements. We continuously evaluate industry drilling techniques and monitor the results of other operators to improve our operating practices, and we expect the development techniques utilized by us to continue to evolve.

· Leverage our relationship with our affiliates to efficiently operate our current assets and opportunistically expand our position in the Eagle Ford Shale and other producing areas. SOG, headquartered in Houston, Texas, is a privately owned full service oil and natural gas operating company engaged in the exploration and development of oil and natural gas assets primarily in the South Texas, Louisiana and onshore Gulf Coast areas on behalf of certain of its affiliates, including the Company, pursuant to existing management services agreements. The Company refers to SOG and its affiliates (excluding Sanchez Energy), collectively, as the "Sanchez Group." Various members of the Sanchez Group have been actively involved in the oil and natural gas industry since 1972 and drilled or participated in more than 4,000 wells, directly and through joint ventures. During this period, they have carefully cultivated relationships with mineral and surface rights owners in and around our core areas and compiled an extensive technological database that we believe gives us a competitive advantage in acquiring additional leasehold positions in these areas. We have been granted access to the proprietary portions of the technological database related to our properties and SOG interprets and uses the database for our benefit. We plan to leverage our affiliates' expertise, industry relationships and scale to efficiently operate our existing assets and evaluate and pursue potential opportunities to expand our position in the Eagle Ford Shale and other producing basins. From time to time, we review acquisition opportunities from third parties or other members of the Sanchez Group.

- Maximize financial flexibility. We seek to demonstrate financial discipline by maintaining a strong liquidity position and pursuing capital strategies that maximize cash flow and return on investment. As of December 31, 2018, we had liquidity of approximately $370.1 million, consisting of approximately $197.6 million of cash and cash equivalents, $25.0 million of available borrowing capacity under the Credit Agreement, and $147.5 million of available borrowing capacity under the SN UnSub Credit Agreement. For a description of current and previous credit agreements along with indentures covering our Senior Notes, refer to “Item 8. Financial Statements and Supplementary Data – Note 6. Debt.” We continually

Table of Contents

evaluate our level of operating activity in light of current and projected commodity prices, our capital resources and cost structure and other considerations, and, based upon this evaluation, may adjust our capital spending as appropriate. As previously disclosed, for 2019 we have elected to significantly reduce our budget to focus on capital preservation and to maximize our liquidity. In addition, we have historically entered into hedging transactions for a portion of our expected oil and natural gas production to achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices.

· Pursue strategic acquisitions to grow our leasehold position in the Eagle Ford Shale and seek opportunistic entry into new basins. We have historically been successful in identifying and acquiring additional acreage and producing assets in the Eagle Ford Shale by leveraging our longstanding relationships in and management's knowledge of the oil and natural gas industry in South Texas. While we seek to continue growing our position in the Eagle Ford Shale, we may also selectively target additional producing areas that we believe offer attractive opportunities to expand our scale of operations.

Our Short Term Business Strategies

In the current low commodity price and capital constrained environment, we intend to remain disciplined and prudent with our investments to maximize financial flexibility. In response to, among other things, the price declines that began in the fourth quarter of 2018, at this time we are primarily focused on lowering cash costs across our business and reducing our financial leverage, with an objective of maximizing our liquidity position and improving our balance sheet.

Our development portfolio is comprised of an extensive inventory of potential future drilling locations, including many that would be economically viable even under current pricing and operating conditions. However, we have elected to pursue a significant reduction in development activity for 2019 with a focus on capital preservation and liquidity. As a result of our reduced investment and the associated curtailment in drilling and completion activities, our production, and possibly our reserves, may decline, particularly if our capital expenditures budget does not increase in 2020, as currently planned, to amounts comparable to our historic (pre-2019) levels. In addition, we may be required to reclassify some portion of our reserves currently booked as PUDs to no longer be proved reserves if we are required to defer planned capital expenditures beyond 2019 due to circumstances we do not currently anticipate or which are beyond our control and, as a result, we are unable to develop such reserves within five years of their initial booking. Over the long term, a continued decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by negatively impacting our cash flow from operations and the value of our assets. We will continue to identify and employ cost-saving measures to more efficiently deploy our capital and to decrease our operating and general and administrative expenses. We are also pursuing a number of strategic alternatives to better align our capital structure with the current low commodity price environment.

Our Competitive Strengths

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

- Strategic, geographically concentrated leasehold position in the Eagle Ford Shale. We have strategically assembled a current leasehold position of approximately 271,000 net acres in the Eagle Ford Shale, which we believe ranks among the highest rate of return unconventional oil and natural gas formations in North America. Our large, geographically concentrated acreage position allows us to establish economies of scale with respect to drilling, production, operating and administrative activities and costs, in addition to further leveraging our base of technical expertise.

- Proven low cost operator. We continually focus on strategies to minimize our cost structure and have historically been recognized as one of the lowest cost operators in the Eagle Ford Shale. We utilize a system of procedures that have facilitated greater coordination across our organization, improved the efficiency of our operations, minimized the cost of sourcing goods and services and reduced the cost of drilling and completing wells. In addition, management takes a rigorous and methodical approach to reducing the total delivered cost of purchased goods and services by examining costs on their most basic level. As a result, goods and services are commonly sourced directly from suppliers. Additionally,

Table of Contents

management regularly reviews the value chain for opportunities to internally provide services in order to further reduce or provide sustainability in current costs.

· Demonstrated ability to drive liquids-weighted production and reserves growth. Our average production for full year 2018 was approximately 78,939 Boe/d (68% liquids), substantially all of which was from the Eagle Ford Shale, which represents an increase of approximately 12% compared to approximately 70,320 Boe/d (65% liquids) for the full year 2017. In addition, our total proved reserves at December 31, 2018 were 380.4 MMBoe (67% liquids), an increase of approximately 5% over the prior year.

· Extensive, multi year drilling inventory. As of December 31, 2018, we had an inventory of over 2,125 net locations for potential future drilling on our acreage position in the Eagle Ford Shale, which we believe offers many years of development opportunities.

· 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 management experience at other public companies. Furthermore, members of the Sanchez Group have more than 40 years of operating history in our core areas, providing us with extensive knowledge 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 production and reservoir engineers, drilling and completion engineers, geologists and geophysicists, along with other support personnel. SOG's technical team has significant experience and expertise in applying the most sophisticated technologies used in developing conventional and unconventional resource plays, including 3 D seismic interpretation capabilities, horizontal drilling, comprehensive multi stage hydraulic stimulation programs and other exploration, production and processing technologies. We believe this technical expertise is integral to the successful development of our assets, including the potential for defining future new core producing areas in other established and emerging basins.

Core Properties

Eagle Ford Shale

We and our predecessor entities have a long history in the Eagle Ford Shale where, as of December 31, 2018, we have assembled approximately 472,000 gross leasehold acres (approximately 271,000 net acres) and have over 4,390 gross (2,125 net) specifically identified potential future drilling locations. As of December 31, 2018, 987 of these drilling locations represented PUDs and were developed using existing geologic and engineering data. Although the approximately 3,403 gross additional non-proved locations identified by our management were determined using the same geologic and engineering methodology as those locations to which proved reserves are attributed, they fail to satisfy all criteria for proved reserves for reasons such as development timing, economic viability at Securities and Exchange Commission ("SEC") pricing and production volume certainty. In evaluating and determining those locations, we also considered the availability of local infrastructure, drilling support assets, property restrictions and state and local regulations. The Company updates its estimate of identified potential future drilling locations from time to time based on various factors, including actual results from recently drilled and completed wells, changes in well-spacing strategies and other observed performance and operating trends. The Company reduced its estimate of identified potential future drilling locations during the fourth quarter 2018 primarily to reflect early results from recently drilled and completed wells in the horizon commonly referred to as the Upper Eagle Ford in our Comanche area and adjustments related to increased well-spacing in our Catarina and Comanche areas based on trial activity. The increase in well-spacing is intended to maximize the expected ultimate hydrocarbon recovery of new wells and reduce the risk of negatively impacting the productivity of other nearby wells. We may increase or decrease our estimated inventory of potential future drilling locations as appropriate based on additional information and performance data. Our estimate of potential future drilling locations was derived based on evaluations designed to optimize the value of our oil and natural gas properties and the efficiency of our multi-year development program and is not intended to represent an actual forecast or limitation in the number of locations that may be drilled. The locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors, and may differ from the locations currently identified. With our limited capital budget for 2019 (or if we do not increase our capital expenditures budget in 2020), many of our identified drilling locations may

Table of Contents

be uneconomic at current or projected prices. See Item 1A. Risk Factors – "Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the timing or occurrence of their drilling." For the year 2019, we plan to invest the majority of our capital budget in the Eagle Ford Shale.

In 2017, we acquired approximately 252,000 gross (61,000 net) acres in Dimmit, Webb, La Salle, Zavala and Maverick counties, Texas through the Comanche Acquisition, representing a 24% working interest in the asset, which we refer to as the Comanche area. We have identified approximately 2,800 gross (680 net) Eagle Ford locations for potential future drilling in our Comanche area.

In the Comanche area, we have a development commitment that, in addition to other requirements in the leases that must be met in order to maintain our acreage position, requires us to complete and equip 60 wells in each annual period commencing on September 1, 2017 and continuing thereafter until September 1, 2022 or pay a penalty for the failure to do so. Up to 30 wells completed and equipped in excess of the annual 60-well requirement can be carried over to satisfy part of the 60-well requirement in subsequent annual periods on a well-for-well basis. As of August 31, 2018, the Company achieved a 30-well bank at Comanche that can be applied toward its current annual development commitment for the period that extends from September 1, 2018 to August 31, 2019. The Company completed and equipped an additional 27 wells at Comanche between September 1, 2018 and December 31, 2018, resulting in a total of 57 wells that can be applied toward the current annual development commitment of 60 wells. The Company's 2019 capital budget includes the additional activity needed to meet the annual development commitment at Comanche for the period September 1, 2018 to August 31, 2019. SN Maverick is currently engaged in a disagreement with Blackstone regarding operations of the Comanche Assets under the joint development agreement with Blackstone (the "JDA"). Among other things, Blackstone has asserted that SN Maverick is in default of the JDA and Blackstone has the right to take over operations of the Comanche Assets. Although SN Maverick disputes Blackstone's assertions and has asserted defenses to the allegations and its own counterclaims against Blackstone, if Blackstone prevails in the disagreement, SN Maverick would lose its rights to operate the Comanche Assets and certain rights of SN Maverick under the JDA, including the ability to vote or appoint representatives to the operating committee or to transfer the Comanche Assets, among others. Furthermore, Blackstone has attempted to initiate a division of operatorship under the JDA pursuant to which operatorship of the Comanche Assets would be divided between Blackstone (or a third-party operator) and SN Maverick in accordance with certain procedures specified in the JDA. Loss of operatorship of some portion or all of the Comanche Assets, or a finding that SN Maverick is in default under the JDA, would have a material adverse effect on our business, financial condition or results of operations.

We have approximately 106,000 net acres in Dimmit, La Salle and Webb counties, Texas representing a 100% working interest, which we refer to as the Catarina area. We have identified approximately 575 gross (575 net) locations for potential future drilling in our Catarina area.

In the Catarina area, we have a drilling commitment that requires us to drill (i) 50 wells in each 12-month 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 12-month period on a well-for-well basis. As of June 30, 2018, the Company achieved a 26-well drilling bank at Catarina that can be applied toward its current annual drilling commitment for the period that extends from July 1, 2018 to June 30, 2019. The Company drilled an additional 36 wells between July 1 and December 31, 2018 at Catarina, resulting in a total of 62 wells toward the current annual drilling commitment of 50 wells. Accordingly, the Company has met its annual drilling commitment for the period July 1, 2018 to June 30, 2019 and has initiated a bank of 12 wells toward the next annual drilling commitment period, which begins on July 1, 2019.

We have approximately 96,000 net acres in Dimmit, Frio, La Salle, and Zavala counties, Texas, which we refer to as the Maverick area, which we believe lies in the black oil window. We have identified approximately 790 gross (760 net) locations for potential future drilling in our Maverick area.

We have approximately 7,600 net acres in Gonzales County, Texas, which we refer to as the Palmetto area, which we believe lies in the volatile oil window. We have identified approximately 225 gross (110 net) locations for potential future drilling in our Palmetto area.

Table of Contents

Tuscaloosa Marine Shale

As of December 31, 2018, we owned approximately 34,000 net acres in the TMS. Although TMS development is currently challenged due to well costs and commodity prices, we believe that the TMS play has significant future development potential as changes in technology, commodity prices and service costs occur.

Oil and Natural Gas Reserves and Production

Internal Controls

Our estimated reserves at December 31, 2018 were prepared by Ryder Scott Company, L.P. (“Ryder Scott”), our independent third-party reserve engineers pursuant to their report dated February 4, 2019, which is filed as an exhibit to this Annual Report on Form 10-K. We expect to continue to have our reserve estimates prepared annually by third-party reserve engineers. Our internal professional staff works closely with Ryder Scott to ensure the integrity, accuracy, completeness and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our reserve engineering database is provided to the third-party 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 third-party engineers as part of their evaluation of our reserves.

Technology Used to Establish Reserves

Under SEC rules, 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 undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data assessments of 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. Gregory A. Avra is the technical professional primarily responsible for overseeing the preparation of our reserve estimates. Mr. Avra has over 30 years of industry experience, serving in positions of increasing responsibility in engineering and reserve evaluations with various public and private oil and natural gas companies. He holds a Bachelor of Science in petroleum engineering from Texas A&M University and is a Licensed 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

Table of Contents

Scott's compensation for the required preparation of its report is not contingent upon the results obtained and reported, and Ryder Scott has not performed other work for SOG or us that would affect its objectivity. The engineering information presented in Ryder Scott's report was overseen by Eric Nelson. Mr. Nelson has been practicing petroleum engineering since 2002 and has more than 13 years of experience with Ryder Scott. He holds a Bachelor of Science in chemical engineering from the University of Tulsa and a Master of Business Administration from the University of Texas. Mr. Nelson is a Licensed Professional Engineer in the State of Texas.

Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves and the associated Standardized Measure amounts attributable to our properties as of December 31, 2018, based on a reserve report prepared by Ryder 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.

Table of Contents

	As of December 31, 2018				
	Oil (MMBbls)	Natural Gas Liquids (MMBbls)	Natural Gas (Bcf)	Total Estimated Proved Reserves (MMBoe)(2)	PV-10 (in millions)(3)
Reserve data (1):					
Estimated proved reserves by area:					
Eagle Ford:					
Comanche EF(4)	49.4	47.9	264.0	141.2	$ 1,029.7
Catarina	52.3	85.4	494.3	220.1	1,334.1
Maverick	14.3	0.1	0.7	14.5	194.8
Palmetto	2.2	0.5	3.0	3.3	28.0
Total Eagle Ford	118.2	133.9	762.0	379.1	2,586.6
TMS	0.3	—	—	0.3	5.8
Other Assets	0.8	0.1	0.3	1.0	15.6
Total	119.3	134.0	762.3	380.4	$ 2,608.0
Standardized Measure (in millions) (1)(5)					$ 2,474.8
Estimated proved developed reserves by area:					
Eagle Ford:					
Comanche EF(4)	25.8	29.3	161.4	81.9	$ 713.9
Catarina	17.7	36.5	211.4	89.4	729.5
Maverick	6.6	0.1	0.7	6.8	155.9
Palmetto	0.2	—	0.2	0.3	6.0
Total Eagle Ford	50.3	65.9	373.7	178.4	1,605.3
TMS	0.3	—	—	0.3	5.8
Other Assets	0.8	0.1	0.3	1.0	15.6
Total	51.4	66.0	374.0	179.7	$ 1,626.7
Estimated PUDs by area:					
Eagle Ford:					
Comanche EF(4)	23.6	18.6	102.6	59.3	$ 315.8
Catarina	34.6	48.9	282.9	130.7	604.6
Maverick	7.7	—	—	7.7	38.9
Palmetto	2.0	0.5	2.8	3.0	22.0
Total Eagle Ford	67.9	68.0	388.3	200.7	981.3
TMS	—	—	—	—	—
Other Assets	—	—	—	—	—
Total	67.9	68.0	388.3	200.7	$ 981.3

(1)Our estimated net proved reserves and related Standardized Measure were determined in accordance with SEC guidelines 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 12 months were $65.56 per Bbl for WTI Cushing oil, $37.58 per Bbl for NGLs and $3.10 per MMBtu for Henry Hub natural gas at December 31, 2018. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing premiums or deductions and other factors affecting the price realized at the wellhead. For the year ended December 31, 2018, the average realized prices for oil, NGLs and natural gas were $64.63 per Bbl, $23.36 per Bbl and $3.16 per Mcf, respectively.

Table of Contents

(2) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(3) PV-10 is a non-GAAP financial measure. See “Item 6. Selected Financial Data – Non-GAAP Financial Measures” for a reconciliation of PV-10 to Standardized Measure.

(4) SN Comanche Assets exclude approximately 16,100 net acres of deep rights only, which includes the Pearsall Shale.

(5) Standardized Measure is calculated in accordance with Accounting Standards Codification (“ASC”) 932, Extractive Activities—Oil and Gas. For further information regarding the calculation of 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 information in the table above represents estimates only. Oil, natural gas and NGL reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGLs 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. Generally, lower prices adversely impact the quantity of our reserves as those reserves may no longer meet the economic producibility criteria under SEC rules or may be removed due to a lower amount of capital available to develop these projects within the SEC-mandated five-year limit. 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 regarding the timing and volume of future production, which may prove to be inaccurate.

Development of PUDs

None of our PUDs at December 31, 2018 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. Historically, our drilling and development programs were funded primarily with cash flow from operations, proceeds from borrowings and the issuance of debt and equity securities. Based on our current expectations of our cash flows and drilling and development programs, which includes the drilling of PUD locations, we believe that we can fund the drilling of our current inventory of PUD locations and our expansions and extensions over the next five years from our cash on hand combined with cash flow from operations, utilization of available borrowing capacity under our revolving credit facilities and external sources of capital, which may include proceeds from asset sales or the issuance of additional securities. See Item 1A. Risk Factors – "Approximately 53% of our total estimated proved reserves at December 31, 2018 were PUDs requiring substantial capital expenditures and may ultimately prove less than estimated." 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, 2018, we have identified 987 gross (483 net) PUD drilling locations which we anticipate drilling within the next five years. The table below provides a reconciliation of our PUD locations from December 31, 2017 to December 31, 2018:

	Net Oil (MBbls)	Net Natural Gas Liquids (MBbls)	Net Natural Gas (MMcf)	Net Volume (MBoe)
PUDs as of December 31, 2017	67,897	54,380	386,603	186,711
Revisions of previous estimates:				
Revisions due to price change	64	28	154	118
Technical revisions	(26,032)	(13,358)	(152,965)	(64,884)
Extensions and discoveries	33,438	35,203	201,745	102,265
Purchases	—	—	—	—
Divestitures	—	—	—	—
Conversion to proved developed reserves during the year	(7,350)	(8,262)	(47,255)	(23,488)
PUDs as of December 31, 2018	68,017	67,991	388,282	200,722

Our year end development plans and associated PUDs are consistent with SEC guidelines for development within five years. Our current capital budget for 2019 includes approximately $100 million to $150 million for the drilling and completion of wells, with a primary focus on the development of PUD locations and other lower risk activities. Technical revisions of PUD estimates represent changes in forecasted performance, development strategy and timing. Prolonged or further declines in commodity prices could require us to reduce expected capital spending over the next five years, potentially impacting either the quantity or the development timing of PUDs.

For more information about our historical costs associated with the development of PUDs, please read “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, Price and Cost History

The following table sets forth information regarding combined net production by area 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,		
	2018	2017	2016
Production:			
Oil (MBbls)			
Comanche	4,447	3,129	—
Catarina	3,508	3,180	3,615
Maverick	1,503	1,382	858
Palmetto	102	241	351
Cotulla	—	30	810
Marquis	—	222	693
TMS / Other	95	33	44
Total	9,655	8,217	6,371
Natural gas liquids (MBbls)			
Comanche	3,937	3,025	—
Catarina	5,941	5,166	5,475
Palmetto	32	55	78
Maverick	26	48	14
Cotulla	—	1	237
Marquis	—	47	156
TMS / Other	—	—	—
Total	9,936	8,342	5,960
Natural gas (MMcf)			
Comanche	21,472	17,615	—
Catarina	33,563	36,255	40,544
Palmetto	163	305	494
Maverick	132	281	93
Cotulla	—	(9)	1,393
Marquis	—	206	656
TMS / Other	—	(2)	9
Total	55,330	54,651	43,189
Net production volumes:			
Total oil equivalent (MBoe)	28,813	25,667	19,529
Average daily production (Boe/d)	78,939	70,320	53,358
Average sales price (1):			
Oil ($ per Bbl)	$ 64.63	$ 48.69	$ 37.95
Natural gas liquids ($ per Bbl)	$ 23.36	$ 20.52	$ 13.72
Natural gas ($ per Mcf)	$ 3.16	$ 3.10	$ 2.50
Oil equivalent ($ per Boe)	$ 35.79	$ 28.84	$ 22.09
Average unit costs per Boe:			

Oil and natural gas production expenses	$ 10.60	$ 9.52	$ 7.97
Production and ad valorem taxes	$ 1.96	$ 1.43	$ 1.01
General and administrative expenses(2)	$ 3.40	$ 5.63	$ 5.65
Depreciation, depletion, amortization and accretion	$ 9.11	$ 6.90	$ 7.55
Impairment of oil and natural gas properties	$ 0.50	$ 1.54	$ 2.43

(1) Excludes the impact of derivative instrument settlements.

Table of Contents

(2) Includes non-cash stock-based compensation expense of $0.8 million, $22.9 million and $25.0 million for the years ended December 31, 2018, 2017 and 2016, respectively, and includes acquisition and divestiture costs of $0.8 million, $30.5 million and $8.4 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Drilling Activities

The following table sets forth information with respect to the number of 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. With our limited capital budget for 2019 (or if we do not increase our capital expenditures budget in 2020), many of our identified drilling locations may be uneconomic at current or projected prices. At December 31, 2018, 39 gross (22 net) wells were in various stages of completion.

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	206.0	96.0	233.0	123.9	67.0	64.0
Dry (1)	2.0	1.0	1.0	1.0	1.0	1.0
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	206.0	96.0	233.0	123.9	67.0	64.0
Dry (1)	2.0	1.0	1.0	1.0	1.0	1.0

(1)This classification represents wells which experienced mechanical issues during development operations and were unable to be completed.

The following table sets forth information at December 31, 2018 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		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated by us	332	151	1,970	820	2,302	971

Non-operated	95	11	1	—	96	11
Total	427	162	1,971	820	2,398	982

Table of Contents

Developed and Undeveloped Acreage

The following table sets forth our estimated gross and net developed and undeveloped acreage as of December 31, 2018. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary table.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Comanche EF (1)	131,700	32,087	119,398	29,090	251,098	61,177
Catarina	41,925	41,925	64,126	64,126	106,051	106,051
Maverick	8,700	8,434	90,351	87,591	99,051	96,026
Palmetto	3,360	1,660	12,085	5,970	15,445	7,630
Total Eagle Ford	185,685	84,106	285,960	186,777	471,645	270,883
Comanche - Pearsall	—	—	65,595	16,122	65,595	16,122
TMS	1,000	996	33,483	33,343	34,483	34,339
Other	—	—	3,626	3,244	3,626	3,244
Total	186,685	85,102	388,664	239,486	575,349	324,588

(1) SN Comanche Assets exclude 16,122 net acres of deep rights only, which includes the Pearsall Shale.

As of December 31, 2018, approximately 77% of our net acreage was held by production and/or continuous operations. We also have leases that were not held by production and/or continuous operations representing approximately 66,000 net acres (of which approximately 54,000 net acres were in the Eagle Ford Shale) expiring in 2019, approximately 6,000 net acres (all of which were in the Eagle Ford Shale) expiring in 2020, and approximately 4,000 net acres (all of which were in the Eagle Ford Shale) expiring in 2021 and beyond. Of the 54,000 net Eagle Ford acres set to expire in 2019, approximately 45,000 net acres are subject to two-year extension options, or drilling commitments, which would permit us to extend the primary term of those leases into 2021. In addition, we have a continuous drilling commitment 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. We also have a continuous development commitment in our Comanche area that, among other requirements, must be met in order to maintain our acreage position requiring us to complete and equip 60 wells in each of five consecutive annual periods beginning September 1, 2017 or pay a penalty for the failure to do so. We anticipate that our current and future drilling plans along with selected lease extensions should address the majority of our leases subject to potential expiration in the Eagle Ford Shale in 2019 and beyond.

Delivery Commitments

As is common in our industry, we have made commitments to certain purchasers to deliver a portion of our production from our Catarina and Comanche areas.

Catarina Area

As of December 31, 2018, in our Catarina area, we have three contracts that require us to deliver portions of our natural gas, with delivery requirements through 2020, 2021 and 2022, respectively. Under the Gathering Agreement (as defined in "Item 8. Financial Statements and Supplementary Data – Note 10, Related Party Transactions") expiring in 2020 through the Catarina Midstream gathering facilities, and under our contracts expiring in 2021 and 2022, we are required to deliver a total volume commitment of 61.0 Bcf, 47.5 Bcf and 158.3 Bcf of natural gas, respectively. During 2018, we recorded expenses related to deficiencies on delivery commitments of approximately $4.7 million. These amounts were recorded to the "Oil and natural gas production expenses" line item 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 2019 related to deficiencies on our natural gas delivery commitments.

Table of Contents

The Gathering Agreement also requires us to deliver a portion of our oil production through the Catarina Midstream gathering facilities. Under this contract, which expires in 2020, we are required to deliver approximately 3.8 MMBbls of oil. We do not expect to have additional expenses in 2019 related to deficiencies on our oil delivery commitments.

Comanche Area

We, as the operator in our Comanche area, on behalf of ourselves and other working interest partners, are party to two gathering agreements that require us to deliver variable monthly quantities of oil and natural gas through 2034. Gross volumes under these contracts peak at approximately 63,100 Bbl per day (approximately 15,200 Bbl per day net) of oil and condensate in 2020 and 430,200 Mcf per day (approximately 103,600 Mcf per day net) of natural gas in 2022, and then decrease annually thereafter, through the end of the contracts. We are currently meeting our minimum volume commitments under these contracts; however, we expect to incur expenses in 2019 related to deficiencies on these commitments in connection with anticipated reduced capital activity levels.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to one contract that requires us to deliver portions of our oil. This contract expires in 2020 and requires us to deliver approximately 3.0 MMBbls of oil. During 2018, we recorded expenses related to deficiencies on delivery commitments of approximately $0.8 million. We do not expect to have additional expenses in 2019 related to deficiencies on our oil delivery commitments.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to three contracts that require us to deliver portions of our natural gas, with delivery requirements through 2022 (in the case of one of the contracts) and 2023 (in the case of the remaining two contracts). Under the contract expiring in 2022, we are required to deliver approximately 23.1 Bcf of natural gas. Under the contracts expiring in 2023, we are required to deliver approximately 71.2 Bcf and 119.6 Bcf, respectively, of natural gas. During 2018, we recorded expenses related to deficiencies on delivery commitments of approximately $0.5 million. We expect to have additional expenses in 2019 related to deficiencies on our natural gas delivery commitments in connection with anticipated reduced capital activity levels.

We, as the operator, on behalf of ourselves and the other working interest partners, are party to one contract that requires us to deliver portions of our NGLs. This contract expires in 2023 and requires us to deliver approximately 12.5 MMBbls of NGLs. During 2018, we recorded expenses related to deficiencies on delivery commitments of approximately $0.1 million. We do not expect to have additional expenses in 2019 related to deficiencies on our NGL 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 the majority of our wells range from 19.8% to 28.0%, resulting in a net revenue interest to us ranging from 72.0% to 80.2%.

Marketing and Major Customers

For the year ended December 31, 2018, purchases by four of our customers accounted for more than 10% (31%, 25%, 17% and 17%, respectively) of our total revenues. The four customers, who are not affiliates of the Company, purchased oil, natural gas and NGLs from us pursuant to marketing agreements. Since the oil, natural gas and NGLs 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 these products in the areas in which we operate, if we were to lose one or more customers, we believe that we could readily make alternative arrangements such that the purchase of our production volumes would not be materially affected for any significant period of time.

Table of Contents

Hedging Activities

We have historically entered 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 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—Operating Costs and Expenses—Commodity Derivative Transactions” and “Item 7A. Quantitative and Qualitative Disclosures about Market Risk.”

Competition

We operate in a highly competitive environment for leasing and acquiring properties and attracting and retaining qualified personnel. Our competitors specifically include major and independent oil and natural gas companies that operate in our core areas. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. 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 identify and evaluate suitable properties and to consummate transactions in a highly competitive environment. In addition, the capital markets have become more constrained for the oil and natural gas industry, which has led to substantial competition for funding and other financial resources to pursue acquisitions and general business opportunities.

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

Table of Contents

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”) and the Texas Railroad Commission (“Commission”), 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 or injection activities on certain lands lying within wilderness, wetlands, seismically active areas, 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, liability under such laws and regulations is often strict (i.e., no showing of “fault” is required) and can be joint and several.

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, the U.S. 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 historic trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment. 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 could 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 laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that this situation 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

Table of Contents

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 are subject to strict liability that, in some circumstances, may be joint and several 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 common law-based 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 the U.S. Congress to re-categorize certain oil and natural gas exploration and production wastes as “hazardous wastes.” Also, in December 2016, the EPA agreed in a consent decree to review its regulations of oil and natural gas waste. It has until March 2019 to determine whether any revisions are necessary. 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.

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

Table of Contents

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 the 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 ("Corps"). On June 29, 2015, the EPA and the Corps jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. The rules are subject to ongoing litigation and have been stayed in more than half the States, including Texas, Louisiana and Mississippi. Also, on December 11, 2018, the EPA and the Corps released a proposed rule that would replace the 2015 rule, and significantly reduce the waters subject to federal regulation under the Clean Water Act. The proposal is currently subject to public review and comment, after which additional legal challenges are anticipated. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act. To the extent the rules expand the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

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.

Furthermore, the EPA is examining regulatory requirements for "indirect dischargers" of wastewater – i.e., those that send their discharges to private or publicly owned treatment facilities, which treat the wastewater before discharging it to regulated waters. On June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

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.

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. The OPA subjects owners of facilities to strict liability that, in some circumstances, may be joint and several for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

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 spill prevention, control and countermeasure plans in connection with on-site storage of significant quantities of oil. 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. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

Table of Contents

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important and common 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 production of oil and/or natural gas. The SDWA regulates the underground injection of substances through the Underground Injection Control, or UIC, Program. Hydraulic fracturing is generally exempt from regulation under the UIC Program, and thus the hydraulic fracturing process 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 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, Mississippi, and Louisiana, where we maintain acreage, the EPA is encouraging state programs to review and consider use of the above-mentioned guidance. In addition, legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of the U.S. Congress.

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. Accordingly, we set surface casing strings below the deepest usable quality fresh water zones and cement them back to the surface in accordance with applicable regulations, potential lease requirements and other legal requirements to ensure protection of existing fresh water zones. Also, prior to commencing drilling operations for the production portion of the hole, the surface casing strings are pressure tested to ensure mechanical integrity.

Although not presently relevant to our current 2019 development plans, on March 26, 2015, the Bureau of Land Management (“BLM”) published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. However, on March 28, 2017, President Trump signed an executive order directing the BLM to review the rule and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. This decision has been challenged by state and environmental groups. At this time, it is uncertain when, or if, the rule will be implemented.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, on December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing to impact drinking water resources finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing or the disposal of produced water and flowback fluid in underground injection wells under the SDWA or other regulatory mechanism.

Also, some states have adopted, and other states are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or otherwise

Table of Contents

require the public disclosure of chemicals used in the hydraulic fracturing process. For example, in December 2011, the Commission adopted rules and regulations requiring that oil and natural gas operators publicly disclose the chemicals used in the hydraulic fracturing process. 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. Additionally, on October 28, 2014, 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, which became effective on November 17, 2014, 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 Commission has used this authority to deny permits for waste disposal sites.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. These or any other new laws or regulations that significantly restrict hydraulic fracturing or the disposal of produced water and flowback fluid in underground injection wells 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.

Further federal, state and/or local laws governing hydraulic fracturing could result in additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, more stringent plugging and abandonment requirements and potential increases in costs. Such 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 additional federal or state and/or local laws are enacted.

Air Emissions

The federal Clean Air Act, as amended, 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. On August 16, 2012, the EPA published final rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. The rules include NSPS for completions of hydraulically fractured gas wells and establish specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in Volatile Organic Compounds (“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. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation’s energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. Also, on October 15, 2018, the EPA published a proposed rule to significantly reduce regulatory burdens imposed by the 2016 regulations, including, for example, reducing the monitoring frequency for fugitive emissions and revising the requirements for pneumatic pumps at well sites.

Table of Contents

Also, on November 15, 2016, the BLM finalized a waste prevention rule to reduce the flaring, venting and leaking of methane from oil and natural gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. State and industry groups have challenged this rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rule and, if appropriate, to initiate a rulemaking to rescind or revise it. On April 4, 2018, a federal district court stayed certain provisions of the rule pending the BLM's reconsideration and, on September 28, 2018, the BLM finalized revisions to the waste prevention rule to reduce "unnecessary compliance burdens." The States of California and New Mexico have challenged the scaled-back rule. At this time, it is uncertain when, and to what extent, the waste prevention rule will be implemented.

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

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases, or GHGs. The EPA has finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs.

Furthermore, in December 2015, the United States participated in the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016 and establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and natural gas industry. 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.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with

Table of Contents

our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. For a more complete description of the potential risks associated with climate change initiatives or the physical impacts of climate change, please see Item 1A. Risk Factors – "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."

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 U.S. Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment 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. However, to the extent our current or future activities on federal lands are subject to the requirements of NEPA, this process has the potential to delay the receipt of governmental permits and 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

The Federal Endangered Species Act, or the ESA, and analogous state statutes restrict activities that may adversely threatened or endangered species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, though, in December 2017, the U.S. Fish and Wildlife Service provided guidance limiting the reach of the Act. Federal agencies are required to ensure 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.

Occupational Safety and Health Act

We are also subject to the requirements of the Occupational Safety and Health Act, or 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.

Table of Contents

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.

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 ("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 also contemplated 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. The FERC ultimately determined that imposing a quarterly

Table of Contents

reporting requirement is not necessary at this time and exercised its discretion to terminate the Notice of Inquiry on November 17, 2015.

Although natural gas prices are currently unregulated, the U.S. 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 the U.S. 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 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.

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 do not have any employees. Pursuant to our Services Agreement, SOG performs services for us, including the operation of our properties. Please also read “Item 8. Financial Statements and Supplementary Data —Note 10, Related Party Transactions.” As of February 26, 2019, SOG had 266 employees. 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 office space with other members of the Sanchez Group under leases entered into by the Company and SOG in Houston, Texas at 1000 Main Street, Suite 3000, Houston, Texas 77002. We also have field offices in Carrizo Springs, Catarina and San Antonio, Texas.

Available Information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. 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.

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.

Table of Contents

Item 1A. Risk Factors

Our business involves a high degree of risk. You should read carefully and consider 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, were to occur, our business, financial condition or results of operations could be adversely affected. The risks below are not the only ones facing the 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. Also, please read "Cautionary Note Regarding Forward-Looking Statements."

Risks Related to Our Business

Market conditions for oil, natural gas and NGLs are highly volatile. A sustained decline 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 countries producing oil, natural gas and NGLs, 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 prices for oil, natural gas and NGLs;
- 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 and alternative fuel requirements;
- the proximity, capacity, cost and availability of production and transportation facilities for oil, natural gas and NGLs;
- the availability of refining capacity; and
- the price and availability of, and consumer demand for, alternative fuels.

Governmental actions may also affect prices for oil, natural gas and NGLs. In the past, prices for oil, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. Beginning in the latter half of 2014, oil prices declined precipitously, and continued to decline throughout 2015 as well as the start of 2016. Although oil prices rebounded somewhat in 2017, they declined again in the fourth quarter of 2018. Such downward volatility has negatively affected the amount of our net estimated proved reserves and the Standardized Measure of discounted future net cash flows of our net estimated proved reserves. We recorded proved property impairments of $6.6 million and $3.7 million for the years ended December 31, 2018 and 2016, respectively, and we did not record a proved property impairment during the year ended December 31, 2017.

In addition, our revenue, profitability and cash flow depend upon the prices of and demand for oil, natural gas and NGLs, and continued price volatility and low commodity prices, or a sustained drop in prices such as during the fourth quarter of 2018, could continue to negatively affect our financial results and further impede our growth. In particular, sustained declines in commodity prices have and will:

- limit our ability to enter into commodity derivative contracts at attractive prices;
- reduce the value and quantities of our reserves, because declines in prices for oil, natural gas and NGLs 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.

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;

- third parties' confidence in our ability to find and produce oil and natural gas could decline, which could impact our ability to execute on our business strategy;

- it may become more difficult to retain, attract or replace key employees of SOG to perform work on our behalf, particularly if we engage in restructuring or recapitalization transactions;

- 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;

- our suppliers, hedge counterparties, vendors, service providers and other counterparties could renegotiate the terms of our arrangements, terminate their relationship with us or require additional financial assurances from us; and

Table of Contents

- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the oil and natural gas exploration and production industry.

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.

In addition, requests for credit assurances from our contractual counterparties could have a material adverse effect on our business, financial condition and results of operations. For example, on January 4, 2019, one of our contractual counterparties requested irrevocable letters of credit in an aggregate face amount of approximately \$17.1 million as credit assurance under the terms of certain gathering and processing agreements. We issued such letter of credit on January 10, 2019, reducing our borrowing and letter of credit availability under the Credit Agreement to less than \$8 million. Other suppliers, hedge counterparties, vendors, service providers or other counterparties could require additional financial assurances from us under the terms of our respective agreements, which could result in further reductions to our borrowing and letter of credit availability or a diversion of cash on hand from capital expenditures or funding our business to providing security for our counterparties.

If we were to receive a report from our independent registered public accounting firm with our annual audited financial statements containing a going concern or like qualification or exception, this would constitute an event of default under the Credit Agreement, which may result in cross-defaults under our other debt obligations.

The Credit Agreement requires that our annual audited financial statements include a report from our independent registered public accounting firm without a going concern or like qualification or exception and without any qualification or exception to the scope of the audit. If we were to receive a report from our independent registered public accounting firm with our annual audited financial statements containing a going concern or like qualification or exception, it would constitute an event of default under the Credit Agreement, and the lender under the Credit Agreement would be able to accelerate the repayment of debt under the Credit Agreement and require cash collateralization of any outstanding letters of credit. If this were to occur, we would be unable to make further draws under the Credit Agreement unless the default was waived by the lender under the Credit Agreement. In addition, even if the lender were to waive compliance with this covenant under the Credit Agreement, failure to comply with certain operational covenants under the Credit Agreement relating to payment or performance of certain obligations under the Credit Agreement could result in other events of default. Any acceleration of our debt obligations under the Credit Agreement, if, together with any other accelerated debt obligations equal to or exceeding \$20 million, would trigger cross-acceleration provisions under the indentures governing the 7.75% Notes and 6.125% Notes and, potentially, those under the indenture governing the 7.25% Senior Secured Notes as a result. As of February 26, 2019 we had approximately \$17.1 million in letters of credit outstanding under the Credit Agreement and no borrowings. See "—Restrictive covenants may adversely affect our operations."

We are evaluating a variety of strategic alternatives to improve our balance sheet and to satisfy our obligations under our debt instruments; however, there is no guarantee that any such alternatives can be effectuated on acceptable terms or at all, and such alternatives could adversely affect our creditors and put our stockholders at significant risk of losing all of their respective investments in us.

To address our short and long term liquidity needs and to improve our balance sheet, in November 2018 we engaged a financial advisor to explore strategic alternatives. To meet our debt service obligations, capital expenditures and commitments and contingencies, we may undertake one or more actions, such as:

- refinancing or restructuring our debt and/or preferred stock;
- selling assets;
- further reducing or delaying our drilling program; or
- seeking to raise additional capital through non-traditional lending or other private sources of capital.

However, we cannot provide assurance that we will be able to refinance or restructure our debt and/or preferred stock or implement alternative financing plans, if necessary, on commercially reasonable terms or at all, or that implementing any such alternative financing plans would allow us to meet our debt or other obligations. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness, in addition to constituting an event of default or potentially resulting in a cross default under our debt instruments, would likely result in a further reduction of our credit rating, which could further harm our ability to incur additional indebtedness or obtain other financing on acceptable terms, or at all.

Our ability to restructure or refinance our debt and/or preferred stock will depend on numerous factors, including many beyond our control, such as the prevailing commodity price environment, the condition of the capital markets and the economy generally at such time. Any refinancing or restructuring of our debt and/or preferred stock could be at higher interest rates (or higher dividend rates or liquidation preferences, as applicable) and may require us to comply with more onerous covenants, which could further restrict our business operations.

To the extent inadequate cash flows from operations and other available capital resources require us to dispose of material assets or operations to meet our debt service and other obligations, we may not be able to consummate these dispositions for fair market value, in a timely manner, or at all. Furthermore, any proceeds that we could realize from any dispositions may not be adequate to meet our debt service or other obligations then due.

The terms of existing or future debt instruments, including the indentures governing our Senior Notes, may restrict us from adopting some of these alternative financing plans. For example, covenants in our existing debt instruments limit our ability to (i) incur, assume or guarantee additional indebtedness or issue preferred stock; (ii) grant or incur liens to secure indebtedness; (iii) consolidate with or merge with or into, or sell substantially all of our assets to, another person; or (iv) sell or otherwise dispose of assets, including equity interests in subsidiaries.

We cannot guarantee that any particular refinancing or restructuring alternatives, such as refinancing our existing indebtedness or preferred stock, extending the maturity dates of such indebtedness, or otherwise amending the terms thereof, would be sufficient or could be effectuated at all. In addition, to effect any particular refinancing or restructuring plan we may need to seek relief under the U.S. Bankruptcy Code. This relief may include: (i) seeking bankruptcy court approval for the sale or sales of some, most or substantially all of our assets pursuant to section 363(b) of the U.S. Bankruptcy Code and a subsequent liquidation of the remaining assets in the bankruptcy case; (ii) pursuing a plan of reorganization (where votes for the plan may be solicited from certain classes of creditors prior to a bankruptcy filing) that we would seek to confirm (or "cram down") despite any classes of creditors who reject or are deemed to have rejected such plan; or (iii) seeking another form of bankruptcy relief, all of which involve uncertainties, potential delays and litigation risks. Such financing plans would likely adversely affect our creditors and be highly dilutive to holders of our common stock or preferred stock or possibly cause the loss of all or substantially all of their respective investments. Furthermore, in the event of a restructuring, recovery on holders' investment in the common stock would be subject to the liquidation preference (including accumulated and unpaid dividends) of the Series A Convertible Perpetual Preferred Stock, par value $0.01 per share (the "Series A Preferred Stock") and Series B Convertible Perpetual Preferred Stock, par value $0.01 per share (the "Series B Preferred Stock" and, together with the Series A Preferred Stock, the "Preferred Stock").

We may need to seek relief under the U.S. Bankruptcy Code to complete a strategic transaction that restructures or refinances our debt and/or preferred stock. If we seek bankruptcy relief, we expect that our common stockholders and preferred stockholders would likely receive little or no consideration for their interests. In addition, unsecured creditors would likely realize recoveries significantly less than the principal amount of their claims and, possibly, no recovery at all.

Table of Contents

We believe that a strategic transaction that restructures or refinances our debt and/or preferred stock is critical to our continuing viability. We may need to seek relief under the U.S. Bankruptcy Code to complete such a strategic transaction and address our liquidity needs. A chapter 11 case would have a significant impact on our business. It is impossible for us to predict with certainty the amount of time needed in order to complete an in-court restructuring. If we seek to implement a plan of reorganization under the U.S. Bankruptcy Code, we will need to negotiate agreements with our constituent parties regarding the terms of such plan and such negotiations could take a significant amount of time. A lengthy chapter 11 case would involve significant additional professional fees and expenses and divert the attention of management from operation of the business, as well as create concerns for customers, employees and vendors. There is a risk, due to uncertainty about the future, that (i) employees could be distracted from performance of their duties or attracted to other career opportunities; (ii) our ability to enter into new contracts or to renew existing contracts and compete for new business may be adversely affected; and (iii) we may not be able to obtain the necessary financing to sustain us during the chapter 11 case.

In addition, to successfully complete a restructuring under the U.S. Bankruptcy Code, we could require debtor-in-possession financing, the most likely source of which may be our existing lenders. If we were unable to obtain financing in a bankruptcy case or any such financing was insufficient to fund operations pending the completion of a restructuring, there would be substantial doubt that we could complete a restructuring.

Furthermore, assuming we are able to develop a plan of reorganization, we may not receive the requisite acceptances to confirm such a plan and, even if the requisite acceptances of the plan are received, the Bankruptcy Court may not confirm the plan. If we are unable to develop a plan of reorganization that can be accepted and confirmed, or if the Bankruptcy Court otherwise finds that it would be in the best interest of creditors, or if we are unable to obtain appropriate financing, our chapter 11 case may be converted to a case under chapter 7 of the U. S. Bankruptcy Code, pursuant to which a trustee would be appointed or elected to liquidate our assets for distribution in accordance with the priorities established by the U.S. Bankruptcy Code.

As a result of the foregoing, if we seek bankruptcy relief, we expect that holders of our common stock and preferred stock would likely receive little or no consideration for their securities. In addition, unsecured creditors would likely realize recoveries significantly less than the principal amount of their claims and, possibly, no recovery at all. In particular, we believe that liquidation under chapter 7 of the U.S. Bankruptcy Code would likely result in no distributions being made to our shareholders and, possibly, unsecured creditors.

Even if we are able to complete a strategic transaction to restructure or refinance our debt and/or preferred stock without seeking relief under the U.S. Bankruptcy Code, we may still be unsuccessful in our operating plan, particularly if oil and natural gas prices do not recover. If we are not successful in executing our current plan for operations, we may need to seek relief under the U.S. Bankruptcy Code notwithstanding the success of the strategic transaction. If we seek bankruptcy relief, we expect that holders of our common stock, preferred stock and, possibly, any unsecured notes that remain outstanding would likely receive little or no consideration.

Even if a strategic transaction that restructures or refinances our debt and/or preferred stock without seeking relief under the U.S. Bankruptcy Code is successful, but oil and natural gas prices do not recover or if we are not able to execute our current plan for operations, then we may still need to seek relief under the U.S. Bankruptcy Code notwithstanding the completion of the strategic transaction. If we were to seek relief under the U.S. Bankruptcy Code notwithstanding the completion of the strategic transaction, we expect that the holders of our shares of our common stock, preferred stock and, possibly, unsecured notes would likely receive little or no consideration for their securities.

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

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, we have historically entered into derivative contracts covering a portion of the Company's 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. After the current hedges expire, there is significant uncertainty that we will be able

Table of Contents

to put new hedges in place that will provide us with the same benefit. These derivative contracts may also expose the Company to risk of financial loss (or reduced income) 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, which limits the effectiveness of the hedge itself; or

- the derivative contracts limit the benefit the Company would otherwise receive from increases in commodity prices.

Such financial losses (or reduced income) could materially impact our liquidity, business, financial condition and results of operations.

Further declines in commodity prices or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

All property and acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed. The capitalized costs of our oil and natural gas properties, on a field basis, cannot exceed the estimated future net cash flows of that field. If the net capitalized costs exceed estimated future net revenues, we must write down the costs of each such field to our estimate of fair market value. Unproved properties are evaluated at the lower of cost or fair market value. Accordingly, a significant decline in commodity prices or unsuccessful exploration efforts could cause a future write-down of capitalized costs.

We review the carrying value of our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The impairment analysis is based on then current commodity prices in effect. Once incurred, a write-down of oil and natural gas properties cannot be reversed at a later date even if commodity prices increase. As a result, substantial and sustained declines in oil and natural gas prices such as the one experienced during the fourth quarter of 2018 may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to fund planned capital expenditures.

The Comanche Acquisition or any other acquisition we may undertake involves risks associated with acquisitions and integration of acquired assets, and the intended benefits of the Comanche Acquisition or any other acquisition we may undertake may not be realized.

The Comanche Acquisition or any other acquisition we may undertake involves risks associated with acquisitions and integrating acquired assets into existing operations, including that:

- our senior management's attention may be diverted from the management of daily operations with respect to our Catarina area and our other legacy assets to the integration of the assets acquired in the Comanche Acquisition or other acquisition;

- we could incur significant unknown and contingent liabilities for which we have limited or no contractual remedies or insurance coverage;

- we may be unable to achieve the economies of scale that we expect from integrating the Comanche Assets or any other assets we may acquire into our existing operations;

Table of Contents

- the assets acquired in the Comanche Acquisition or any other acquisition we may undertake may not perform as well as we anticipate; and

- unexpected costs, delays and challenges may arise in integrating the assets acquired in the Comanche Acquisition or any other acquisition we may undertake into our existing operations.

Even if we successfully integrate assets acquired in an acquisition, it may not be possible to realize the full benefits we anticipate or we may not realize these benefits within the expected timeframe. If we fail to realize the benefits we anticipate from the Comanche Assets or any other acquisition we may undertake, our business, results of operations and financial condition may be adversely affected.

We participate in oil and natural gas leases, including with respect to the Comanche Assets, with third parties who may not fulfill their commitments to our projects.

In some cases, we operate but own less than 100% of the working interest in the oil and natural gas leases on which we conduct operations, and other unrelated parties own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person, and many of these factors are outside of our control. We could be held liable for joint activity and gross exposure obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil and natural gas prices such as those experienced in the fourth quarter of 2018 may increase the likelihood that some of these working interest owners are not able or elect not to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

With respect to the Comanche Acquisition, for example, we are the operator of the asset and entered into a development agreement requiring us to complete and equip 60 wells in each annual period commencing on September 1, 2017 and continuing thereafter until September 1, 2022. However, we hold only an approximate 24% working interest in the asset. The risks associated with the joint activity obligations of the other working interest holders exacerbate the risks to us related to completing and equipping the required number of wells in a given year.

Under the terms of the Catarina lease and Comanche development agreement, we are subject to certain annual drilling and development requirements. Failure to comply with these requirements may result in loss of our interests in the Catarina area that are not held by production or sizable default payments to Anadarko, respectively.

In order to preserve our exploration and development rights in the Catarina area, we are required to drill 50 wells per year (measured from July 1 to June 30). If we fail to meet the minimum drilling commitment under the terms of the lease for our Catarina properties (the “Catarina Lease”), we could 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). Up to 30 wells drilled in excess of the minimum 50 wells in a given 12-month period can be carried over to satisfy part of the 50-well requirement in the subsequent annual drilling period on a well-for-well basis. 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 could 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).

We also entered into a development agreement (the “Development Agreement”) with Anadarko regarding the Comanche Assets pursuant to which we committed to completing and equipping 60 wells per year for five years, in addition to other requirements in the leases that must be met in order to maintain our acreage position, or pay a penalty for the failure to do so. The Development Agreement permits up to 30 wells completed and equipped in excess of the annual 60-well requirement to be carried over to satisfy part of the 60-well requirement in subsequent annual periods on a well-for-well basis. If we fail to complete and equip the required number of wells in a given year (after applying any qualifying additional wells from previous years), we and Gavilan are jointly and severally liable to Anadarko for a default fee of $200,000 for each well we fail to timely complete and equip.

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, prices for oil, natural gas and NGLs, 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 provide assurance that we will be able meet our obligations under the Catarina Lease or the Development Agreement. 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 fail to meet our obligations under the Development Agreement we and Gavilan will have to pay Anadarko the applicable default fees, which could adversely affect our business, financial condition and results of operations.

Our agreements with Blackstone and GSO Capital Partners LP (“GSO”) restrict us from transferring our right, title and interest to the Comanche Assets.

Under the terms of the JDA, except under limited circumstances, neither we nor Blackstone can transfer any of our rights, title or interest to any asset or related assets (including any working interests) prior to the third anniversary of the JDA. In addition, under our agreements with GSO, we are not able to dispose of all or a substantial portion of the Comanche Assets without GSO’s consent. These restrictions may prohibit us from taking advantage of certain opportunities, including our ability to sell these assets, which may arise from time to time.

The JDA contains right of first offer (“ROFO”) and tag-along provisions that may hinder our ability to sell our interest in the Comanche Assets within our desired time frame or on our desired terms, and could delay or prevent an acquisition of us, even if the acquisition would be beneficial to our stockholders.

Under the terms of the JDA, both parties have a ROFO in the event that the other party intends to sell or otherwise transfer its interests. In addition, the JDA provides both parties with a tag-along right in the event that the other party intends to sell at least 35% of its total interests to a third-party purchaser (including upon a change of control transaction involving us). These features could limit third-party offers, inhibit our ability to sell our interests or adversely affect the timing of any sale of our interests and our ability to obtain the highest price possible in the event that we decide to market or sell our interests. In addition, the tag-along provisions of the JDA may also frustrate or prevent any attempts by our stockholders or a third-party to replace or remove our current management or to acquire an interest in or engage in other corporate transactions with us, by subjecting certain corporate change of control transactions to a tag-along provision pursuant to which a third-party may be required to acquire Blackstone’s interest in the Comanche Assets if it desires to enter into a corporate transaction with us.

The JDA establishes an operating committee for the Comanche Assets that keeps us from having unilateral control over many key variables of operation and development of the Comanche Assets and also provides for certain circumstances under which we could be removed as operator.

The JDA provides for the administration, operation and transfer of the jointly-owned Comanche Assets. Pursuant to the JDA, the parties thereto established an operating committee, which controls the timing, scope and budgeting of operations on the Comanche Assets (subject to certain exceptions). Although we are designated as operator of the Comanche Assets under the JDA, under certain circumstances (including upon a default under the JDA or a default and acceleration of certain of our debt agreements) we may be removed as operator and, furthermore, because we do not control the operating committee we do not have unilateral control over many key variables of the operation and development of the Comanche Assets, including the establishment of the budget and development plan for the Comanche Assets. There can be no assurance that Blackstone will continue its relationship with us in the future or that we will be able to pursue our stated strategies with respect to the Comanche Assets. Furthermore, Blackstone may (a) have economic or business interests or goals that are inconsistent with ours; (b) take actions contrary to our policies or objectives; (c) undergo a change of control; (d) experience financial and other difficulties; or (e) be unable or unwilling to fulfill their obligations under the JDA, which may affect our financial conditions or results of operations.

SN Maverick is currently engaged in a disagreement with Blackstone regarding operations of the Comanche Assets under the JDA. Among other things, Blackstone has asserted that SN Maverick is in default of the JDA and Blackstone has the right to take over operations of the Comanche Assets. If Blackstone prevails in the disagreement, SN Maverick would lose its rights to operate the Comanche Assets and certain rights of SN Maverick under the JDA, including the ability to vote or appoint representatives to the operating committee or to transfer Comanche Assets, among others. Furthermore, Blackstone has attempted to initiate a division of operatorship under the JDA pursuant to which operatorship of the Comanche Assets would be divided between Blackstone (or a third-party operator) and SN Maverick in accordance with certain procedures specified in the JDA. Loss of operatorship of some portion or all of the Comanche Assets, or a finding that SN Maverick is in default under the JDA, would have a material adverse effect on our business, financial condition or results of operations.

GSO consent is required for agreement of SN UnSub or SN UnSub's general partner to take certain actions, even if we believe the actions to be in the best interests of our stockholders.

Under the amended and restated limited partnership agreement of SN UnSub and limited liability company agreement of SN UnSub's general partner, we are not able to cause SN UnSub or its general partner to take or not to take certain actions unless GSO consents. GSO made a substantial investment (including contributions and other commitments) in SN UnSub at the closing of the Comanche Acquisition and, accordingly, has required that the relevant organizational documents of SN UnSub and its general partner contain certain features designed to provide it with the opportunity to participate in the management of SN UnSub and its general partner and to protect its investment in SN UnSub, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of SN UnSub. These participation and protective features include a governance structure that consists of a board of directors of SN UnSub's general partner, only some of whom we appointed. Furthermore, in case of certain events of default under our debt instruments, our loss of operatorship under the JDA of the Comanche Assets in certain circumstances (including, potentially, as a result of the disagreement with Blackstone referred to above) and other specified events, GSO will gain control of the board of directors of SN UnSub and would have the right to sell SN UnSub or all or substantially all of its assets. Thus, unless GSO concurs, we will not be able to cause SN UnSub and its general partner to take or not to take certain actions, even though those actions may be in the best interest of SN UnSub, its general partner, or us. Furthermore, we, and GSO may have different or conflicting goals or interests which could make it more difficult or time-consuming to obtain any necessary approvals or consents to pursue activities that we believe to be in the best interests of our stockholders. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources."

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

- prices for oil, natural gas and NGLs;
- future production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation;

Table of Contents

- 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, 2018 had decreased by 10%, then the Standardized Measure of our estimated proved reserves as of that date would have decreased by approximately $634 million, from approximately $2,475 million to approximately $1,841 million.

Our Standardized Measure is calculated using unhedged prices for oil, natural gas and NGLs and is determined in accordance with the rules and regulations of the SEC. Over time, we may make material 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.

Our estimated reserves of oil, natural gas and NGLs 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 reserves of oil, natural gas and NGLs, production volumes and cash flow depend on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. Our estimated reserves of oil, natural gas and NGLs will naturally decline over time as they are produced. Our success depends, in part, 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, our production and reserves will continue to decline. Our reduced expected capital investment in 2019 (or in 2020 or thereafter, if we do not increase our capital expenditures budget after 2019, as currently planned) may result in a future decline in our production and reserves. To the extent cash flow from operations and external sources of capital remain limited or become unavailable, our ability to make the necessary capital investments needed to maintain or expand our asset base of oil and natural gas reserves may be diminished. Over the long term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by negatively affecting our cash flow from operations and the value of our assets.

Approximately 53% of our total estimated proved reserves at December 31, 2018 were PUDs requiring substantial capital expenditures and may ultimately prove to be less than estimated.

Recovery of PUDs requires significant capital expenditures and successful drilling operations. At December 31, 2018, approximately 200.7 MMBoe of our total estimated proved reserves were undeveloped. The reserve data included in our reserve report assumes that substantial capital expenditures will be made to develop non-producing reserves over a period of five years. The calculation of our estimated net proved reserves as of December 31, 2018 assumed that we would spend $1.9 million for plugging and abandonment costs and an estimated $100 to $150 million during 2019, with our capital expenditures increasing in 2020 and thereafter to amounts comparable to our historic (pre-2019) levels, to develop our estimated PUDs. Although cost and reserve estimates attributable to our oil and natural gas reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs or capital expenditures will prove to be accurate. Continued declines in commodity prices will reduce the future net revenues of our estimated PUDs and may result in some projects becoming uneconomic. As a result of lower oil and natural gas prices or for other reasons we did not anticipate or which are beyond our control, we may reduce the budgeted capital expenditures for the development of undeveloped reserves in 2019 or in later years. Delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves. Furthermore, our drilling efforts may be delayed or unsuccessful and actual reserves may prove to be less than current reserve estimates, which could have a material

Table of Contents

adverse effect on our financial condition, results of operations and future cash flows.

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. Additionally, drilling wells with no or sub-economic levels of production (dry holes) will negatively impact our financial position. 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 additional pre development expenditures. 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 prices for oil, natural gas and NGLs;

· increases in severance taxes;